

In the Matter of:)
)
Informational Proceeding and)
Preparation of the)
2005 Integrated Energy) Docket No.
Policy Report Update) 04-IEP-01-D
)

PETERS SHORTHAND REPORTING CORPORATION (916) 362-2345

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David K. Maul

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Leon Brathiwaite

Sandra Fromm

Dave Vidaver

ALSO PRESENT

Sepideh Khosrowjah, Regulatory Analyst
California Public Utilities Commission

Hillard Huntington, Stanford University

Kenneth B. Medlock III., Rice University

Luis Pando, Southern California Edison

Walter DiMattia, P. Eng., Supply Advisor
TransCanada

John Bridges, Manager
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ALSO PRESENT (Continued)

Catherine M. Elder, Executive Consultant
RW Beck

Herb Emmrich, Analysis Manager
Southern California Gas Company

Scott Wilder, Business Economics Advisor
The Gas Company

Jeff Huang

Mark Meldgin, Senior Business Partner
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P R O C E E D I N G S

PRESIDING MEMBER GEESMAN: We have a fairly crowded agenda. I am John Geesman, the Energy Commission's Presiding Member of its 2005 Integrated Energy Policy Report.

To my right is Commissioner Jim Boyd, the Associate Member of the Integrated Energy Policy Report Committee and the Presiding Member of the Commission's Natural Gas Committee.

To his right, is his Staff Advisor, Darcie Houck. To my left is Scott Tomashefsky, the Staff Advisor to the Commission Chairman, William Keese.

Our topic today is Forecasting Methodology and Models Used in the Natural Gas Input to the Commission's Integrated Energy Policy Report.

This is a new venue for us, so as I understand it, those who ordinarily participate in our hearings on our webcast are going to get only a visual of our presentation materials.

In order to get an audio feed, you've got to use our call-in number, and could we repeat the call-in number.

MR. MAUL: Yes. The call-in number is

1 1-888-282-8354, the pass code is 56322, and the
2 call leader is Dave Maul, and we will also put a
3 note on our website at the point where the audio
4 visuals are being webcast right now, the note to
5 use that same number.

6 PRESIDING MEMBER GEESMAN: Let me ask
7 all speakers today to make certain to leave a
8 business card with our court reporter who is
9 sitting here at the table to my right.

10 I want to say a couple of things before
11 we get started, and they are fairly broad ranging
12 comments. I'd ask each of the presenters to keep
13 them in mind as we go forward.

14 Our natural gas assumptions are a
15 critical driver to all of the work that the
16 Committee will be doing in the 2005 report cycle.

17 My background is largely from the bond
18 markets, and as a consequence, my personal
19 reliance on models and expectation of what they
20 can provide probably has a faster metabolism
21 associated to it than is ordinary in state
22 government.

23 I was at the Energy Commission in the
24 late 1970's and early 1980's and am familiar with
25 the modeling discipline that we used then. In a

1 field that was largely aimed at a ten or twelve
2 year planning horizon and used principally for
3 power plant siting decision.

4 We are not exactly in that same business
5 any more, and the responsibilities of the
6 Legislature has created for the Integrated Energy
7 Policy Report are substantially broader.

8 I think that one of the things that we
9 need to be most mindful of is the agility and
10 nimbleness of the modeling tools that we use in
11 the natural gas area.

12 I don't have any particular
13 embarrassment or lodge any particular criticism to
14 the fact that the price forecast for natural gas
15 that the Energy Commission utilized in its last
16 Integrated Energy Policy Report cycle adopted just
17 a little over a year ago has missed current price
18 volatility in the natural gas sector by a pretty
19 substantial margin.

20 That forecast may ultimately prove out
21 over the planning horizon which it was aimed at,
22 but I will say that the degree to which we have
23 been off in our assumptions and our inability
24 analytically to re-calibrate on a quick turn
25 around basis, has caused real limitations in state

1 government. We are best off when we make our
2 decisions on the basis of the best information
3 available and the best analysis we can bring to
4 the task at hand.

5 Lacking that or relying on tools that
6 are the equivalent of ocean liners in terms of
7 their ability to turn around quickly, the
8 government tends to resort to policy by anecdote,
9 and that is a fairly dangerous territory to be in.

10 So, I would pose to each of the
11 presentations today, are these the best tools that
12 the state government can be utilizing? Are they
13 sufficiently nimble, are they subject to fairly
14 quick re-calibration, do they meet the needs of
15 the decision makers in state government?

16 We make a lot of big picture judgement
17 calls. We don't make them very frequently, but
18 they are decisions that the government is called
19 upon to make that do involved long-range
20 assumptions, long range planning, and fairly
21 significant significantly opposed alternatives.

22 On the other hand, we make a number of
23 near term corrections to those assumptions as
24 well. I would suggest we probably need a full
25 range of different analytic tools to assist that

1 decision making.

2 To end a sermon, it is a little bit long
3 for me, but Commissioner Boyd, do you have
4 anything to add?

5 COMMISSIONER BOYD: I'd have a tough
6 time topping that, but I would just say to add to
7 that I've been around a long time in government
8 and have been dealt by and victimized by models
9 down through the years.

10 In the early 80's I guess, decision
11 makers were promised that models do give them the
12 decisions they need, and so anecdotal data wasn't
13 even looked at for a while.

14 Everybody soon learned that you can
15 double the time and double the price with regard
16 to the promise of models coming on line and it
17 would help you, so I've been kind of a healthy
18 skeptic and would add, to me, a model is a tool
19 that helps decision makers, but unfortunately you
20 need to use the model as well as some anecdotal
21 data and maybe the seat of your pants a little
22 bit, ultimately, in trying to get close to what
23 might be correct.

24 While at the Commission, I've been
25 associated with natural gas issues since day one,

1 but during the electricity crisis a couple of
2 years proceeding becoming a Commissioner, I also
3 paid attention to natural gas prices for the then
4 governor. You will notice that we didn't run out
5 and buy gas on long term contracts, etc. etc. in
6 the name of the state because we had a good group
7 of people working with us to tell us what the
8 future was.

9 We have been paying attention to gas for
10 quite some time, and the Commission has developed
11 an expertise it didn't have in the past. We
12 really do need to know what are the best and
13 brightest of the modeling tools out there to help
14 us make decisions.

15 We, in concert with the PUC and other
16 state agencies, some of whom are represented in
17 the room, are affected by or have to be players in
18 the arena that deals with natural gas. I love to
19 use the analogy in the California economy sitting
20 on a three legged stool which is electricity,
21 natural gas, and transportation.

22 We are dealing with natural gas which is
23 certainly tied in to the electricity issue which
24 remains a problem for us in this state, so we are
25 really needful of the best and brightest in this

1 particular arena to help us because we have had a
2 tough time. Society has had a tough time coming
3 to grips with the natural gas market to keep us
4 going beyond our glass ceiling. We keep having to
5 sweep up the consequences.

6 So, with that, I look forward to
7 learning a lot today. Thank you.

8 PRESIDING MEMBER GEESMAN: Dave.

9 MR. MAUL: Thank you, Commissioners. My
10 name is David Maul, and I am the Manager of the
11 Natural Gas Office at the Energy Commission.

12 We are pleased to be able to put on this
13 workshop today for not only Commissioner's
14 benefit, staff benefits, and also for the
15 audience's benefit as well.

16 We hope to get quite a variety of
17 information today and following on the theme you
18 heard from Commissioner Geesman, the information
19 that we hope to learn from your presentations and
20 your expertise and your insight is going to help
21 us in three time frames.

22 First in the short term, we are looking
23 at making any minor adjustments so we can enter
24 into our data, our data sources, how we use our
25 data.

1 In the mid term, we are looking at
2 making some fairly modifications to various
3 assumptions, modeling techniques and tools. One
4 of the issues we are raising today is demand
5 elasticity and how we actual build that capability
6 into our modeling efforts and analytical efforts
7 and see whether we can make some progress in that
8 area.

9 Third, in the longer term, we are
10 examining the various times and models that we
11 use, the spread sheets, the various analytical
12 tools, to see whether we need to make some major
13 modifications in the longer term.

14 Obviously, if we were to add models,
15 there is a budgetary process in state government.
16 It does take some time, but we would like to start
17 that process now so we can have things ready for
18 the next Integrated Energy Policy Report.

19 Really we look today at the information
20 we hope to gain will provide a very good
21 foundation for some decisions we are making on the
22 staff level, making recommendations to our
23 commissioners, both short term, mid term, and long
24 term. Hopefully we can all benefit from that.

25 I would like to note that we work very

1 closely with our colleagues at the California
2 Public Utilities Commission. In some ways, we
3 view ourselves as their client. We provide
4 information that is hopefully helpful to them.

5 We work very closely in a variety of
6 issues with them, and I am pleased to note today
7 one of my colleagues from the CPUC, Sepideh
8 Khosrowjah, is sitting here next to me, and her
9 other staff colleagues at the CPUC are listening
10 in as well.

11 As Commissioner did note, Commissioner
12 Geesman noted at the very beginning on the
13 logistical issue, unfortunately, we only have one
14 phone line here not two phone lines, so we have a
15 conference call line set up on the webcast. All
16 the presentations that we were given earlier are
17 being posted on our website so people that are not
18 here in the building today can see what is going
19 on, but they can't hear you live. So, we have a
20 note that is being posted right now for folks to
21 use the conference call line so they can actually
22 hear you as well.

23 As far as logistics today, one more
24 quick note, we do have a sign in sheet over here
25 if you have not yet used the sign in yet, we

1 request that you do, so if we have to get back a
2 hold of you, we can, and ask any follow up
3 questions at all.

4 We do have some set presentations.
5 People have given us presentations in advance up
6 until late last night, so those are out being
7 posted right now hopefully following the agenda
8 that Jariam Gopal, our supervisor, at the Natural
9 Gas Office has put together for us.

10 The format today is Jariam will provide
11 a short overview with a few of our staff on the
12 staff's efforts and how we approach modeling in
13 general, just to kind of set the framework of what
14 we do, how we do it. We don't tend to get into a
15 great amount of detail, nor do we want today to
16 really focus on either projects or particular
17 pieces of data. It is really looking at the
18 approaches today, the models, the methodologies,
19 and not particular projects or outcomes today from
20 our projects.

21 Following that, we have several folks
22 who have asked to make presentations. You will
23 see and hear a wide variety of viewpoints from the
24 various presenters. Then we invite anybody else
25 in the audience to come talk if you have anything

1 else you would like to say. Even although this is
2 a hearing set up, we have talked about it with
3 Commissioners and really view this as more of a
4 workshop, informal workshop format. So, we would
5 really like to have a discussion, a dialogue, not
6 only among ourselves but also with you, and I
7 think really we would like to focus this really on
8 you and the audience because of the knowledge,
9 information, and experience that you are bringing
10 to us. It is really for our benefit, and we do
11 hope to benefit quite a bit from whatever you can
12 offer us today.

13 With that, I think I will turn it over
14 to Jariam Gopal. He has about a twenty minute
15 overview of the Staff's various approaches.

16 Thank you.

17 COMMISSIONER BOYD: Dave, if I may make
18 one added comment. You underscored the fact that
19 this is a workshop, and I think that is something
20 that John and I certainly agree on.

21 This is a workshop. This is not a
22 committee hearing. You've got commissioners and
23 advisors participating here. Unfortunately, the
24 lay out of the room makes it seem a little more
25 intimidating, like a hearing. It isn't, we do

1 want the audience to approach it as a workshop
2 where everybody can kind of free will in terms of
3 participation in the subject matter. I just
4 wanted to underscore what you had said.

5 MR. MAUL: Thank you.

6 MR. GOPAL: Thank you, Commissioners,
7 and thank you, Dave. I will begin this
8 presentation here on the Natural Gas Modeling
9 tools, approaches, methodologies, that we have
10 used in the gas market analysis at the Commission.

11 I'd like to briefly take a few moments
12 to introduce the staff who will be available to
13 answer questions and provide information: Leon
14 Brathiwaite, Mark Di Giovanna, Jim Fore should be
15 here, Bill Wood should be here -- he hasn't made
16 it yet, Mike Purcell, Mignon Marks, and Mary Dyas,
17 I don't know if they are here too today.

18 MR. MAUL: Mary is in training today.

19 MR. GOPAL: All right. We have two
20 student interns, Libby Baseman and Ty Graywall,
21 and we are ready to answer any questions that is
22 necessary.

23 I will begin by talking about briefly on
24 what we do at the Commission. Basically, the
25 items that I want to cover today: Objectives in

1 modeling exercises, Modeling tools used at the
2 Commission, Basics of NARG model that we have
3 used. I will talk a little bit about the modeling
4 system, the assumptions and the methodology that
5 we followed in conducting this analysis.

6 Then I will briefly address the need for
7 the "Integrated Analysis" which probably has been
8 talked about quite a bit with regard to the
9 Integrated Energy Policy Report that we produced
10 last year and we are in the process of doing one
11 for the 2005.

12 We will top this session out with a very
13 few slides on how the electric generation sector
14 is going to be interacting with the gas market and
15 what are the things that we do to coordinate
16 issues on that front.

17 MR. MAUL: Chairman, if I can make a
18 note for folks that are listening in on the
19 conference call and looking at our webcast,
20 Jariam, we are now looking at a power point
21 presentation titled "2005 Integrated Energy Policy
22 Report (Energy Report) Workshop on Modeling
23 December 16th by the Natural Gas Analysis Office.

24 MR. KRUSHNER: David?

25 MR. MAUL: Yes?

1 MR. KRUSHNER: Dan Krushner with the
2 Northwest Gas Association.

3 MR. MAUL: Dan, thanks for calling in.

4 MR. KRUSHNER: A technical question and
5 a process question. I'm on your webcast site, and
6 I am not seeing anything.

7 MR. MAUL: I will call back right now
8 and find out.

9 MR. KRUSHNER: Then a process question.
10 Are you there?

11 MR. MAUL: Yeah, we are conferring right
12 now to find out what is going on here.

13 MR. KRUSHNER: Aren't the documents
14 posted, though.

15 MR. GOPAL: The documents are posted on
16 the website under the 2005 IEPR, that page. So,
17 if you cannot access the web posting, you can go
18 into the 2005 IEPR, follow the workshops documents
19 and notices, go into the December 16 workshop, and
20 there you will find all the presentations on the
21 website.

22 Continuing to slide three, Objectives of
23 Modeling. The basic necessary here, the IEPR
24 Report needs a very comprehensive analysis of the
25 natural gas market. Just as Commissioner Boyd

1 mentioned about the three legged stool that we
2 have, electricity, natural gas, and transportation
3 and gas interfaces with both electricity and the
4 transportation markets.

5 The other major point that I want to
6 make, analysis needs to be coordinated with other
7 energy market analyses, basically electricity
8 analysis, efficiency improvements, renewables, the
9 transportation analysis, and research and
10 development options that are being looked at by
11 the Energy Commission.

12 MR. MAUL: Jariam, excuse me, can we
13 interrupt for a minute. We have some instructions
14 on how to access these visuals on the web page for
15 folks that are listening in, so, Sandra, would you
16 mind giving the instructions.

17 MS. FROMM: Just go the IEPR web page
18 and go under documents which is on the left hand
19 side of the web page. Click on documents, then go
20 to the December 17 Workshop date. If you click on
21 that, then you should be able to pull up all the
22 presentations.

23 PRESIDING MEMBER GEESMAN: December 16.

24 MS. FROMM: I'm sorry, thank you.

25 PRESIDING MEMBER GEESMAN: December 16.

1 MS. FROMM: December 16. I'm sorry.

2 MR. MAUL: Today's date.

3 MR. KRUSHNER: (Inaudible).

4 MR. MAUL: The Energy Commission's web
5 page is www.energy.ca.gov, and the very first page
6 will have an IEPR icon, Integrated Energy Policy
7 Report.

8 MS. FROMM: It is the (indiscernible)
9 button in the middle.

10 MR. MAUL: Let us know -- is there a
11 different number they can call you and get more
12 instructions.

13 MS. FROMM: (Inaudible).

14 MR. MAUL: Okay, Jarlam, go ahead.

15 MR. GOPAL: All right. Thank you. To
16 continue with this, the third point that I wanted
17 to make here is the short-term and long-term
18 analysis are extremely essential.

19 There was a time when we mainly focused
20 on long-term analysis when gas prices were
21 regulated, electricity and market was regulated.
22 The long-term model was what we were mandated to
23 do, but I think things have changed. We need to
24 significantly and comprehensively address short-
25 term markets and seasonal fluctuations to

1 understand what is happening in the energy market
2 place.

3 There are different types of modeling
4 tools available in the area. It could be a
5 qualitative type of models, quantitative modeling.
6 There could be simulation styles where you
7 actually simulate different scenarios. Finally,
8 there is of course the market services where
9 experts can do the analysis and provide you the
10 results that you are looking for.

11 You will note that there is a
12 combination of these types of analyses that are
13 conducted not only at the Commission but outside
14 too. I think we need to see what best matches our
15 needs.

16 Finally, models have "pros and cons"
17 depending on the modularity, depending on the
18 geographic coverage. Are they fundamental or are
19 they empirical, so there is really strengths and
20 weaknesses associated with models that are out
21 there in the market.

22 As I said before, we initially use to
23 produce one report on energy, natural gas markets
24 analysis once every two years. We tried to bring
25 that down to once every year, and we continue now

1 to do it now once a year, but for the IEPR, we
2 will be certainly doing it once every two years.

3 Basically, the information is looked at
4 by the Governor, the Legislature, a variety of
5 industrial participants, by the utility companies,
6 by L & G market now that market is really taking a
7 lot of interest in the local markets.

8 Basically, we at the Commission, try and
9 provide an unbiased objective analysis of the
10 work, the assessments, and the recommendations of
11 impacts and consequences that result from changes
12 in the energy market.

13 Due to lack of time, what I will do is
14 skip maybe some slides or maybe quickly go over
15 some of them because they will be there on the
16 website for people to look at, but in the interest
17 of time, we will try and shorten the discussion
18 here.

19 The analysis process that we follow is
20 basically we start data collection and make sure
21 that we have the information that we need to go
22 ahead. Then we define how we want to look at
23 these things.

24 Do we want to reference case, do we want
25 to talk about a base case, how the market is going

1 to perform over the next ten years or twenty
2 years, make some assumptions on that front. Then
3 we define what the data will be that we will
4 finally use in the analyses.

5 Once this reference case or the base
6 case is defined, we know that there is uncertainty
7 in the market place. We really cannot say what is
8 going to happen, let alone ten years from now,
9 even next year, next month.

10 So, for that, we use sensitivities and
11 scenarios to adverse how this market can vary. We
12 can do sensitivities to address changes in a
13 single variable, and then we use the scenarios to
14 actually consider multiple numbers of variables
15 and how they impact the market place, and then try
16 to define how the world will be five, ten, fifteen
17 years from now.

18 All through this process, we will be
19 analyzing the reference case and the other
20 scenarios and other sensitivities to look at how
21 the results turn out, what are the implications,
22 are we missing something, do we need to add
23 anything else.

24 Last but not least, we do have workshops
25 and hearings for stakeholder input. This is the

1 time when we actually prefer an assessment of what
2 we have done so far in our plans provided to the
3 participants and get their input on what is
4 essential to be covered, what we have missed, and
5 what we not have covered.

6 A few more words on information
7 exchange. Basically, workshops and hearing are
8 the way we communicate with others. In addition
9 to that, we meet with individual companies in a
10 variety of ways several times throughout the
11 process.

12 We also have an annual NARG Model User
13 Conference where we have participants who use this
14 model and participants who are more savvy about
15 the market place, so they can come and talk to us
16 about their expertise and how it relates with the
17 modeling work we do. So, we identify issues that
18 we need to address or the model developer needs to
19 address, so we try to get the most out of this
20 model in our analysis.

21 What are the tools used at the Energy
22 Commission in the gas market? First and foremost,
23 this is the NARG, the North American Regional
24 Natural Gas Model. That's the principle tool used
25 in arriving at all the work that we do.

1 We have used this model since 1989. We
2 developed it over the 1987 to 1989 time frame.
3 Since then, we have been using it in the fuel
4 reports and other reports. We make sure that we
5 try and look at what the model does and how it is
6 structured and make changes to insure that are
7 trying to keep up with the market. Sometimes we
8 keep it up, and sometimes we lag a little bit, but
9 we finally do catch up.

10 Basically, NARG is the main model which
11 looks at the entire continent. In the past, we
12 have looked at U.S. and Canada. Now we have also
13 added Mexico into the big pot of the gas market.

14 We try to capture what is happening in
15 the supply, demand, and transportation regions.
16 While we focus on California and the western
17 states, to some extent we need to look at the
18 North American picture just because the gas market
19 is so integrated. Anything that happens in far
20 out regions can certainly cause some ripple
21 efforts to California. Sometimes the ripples are
22 not too small.

23 Now that was, again, the focus there was
24 long-term issues. Now that we have addressed the
25 need to actually take a short-term market analysis

1 too.

2 We are in the process of developing
3 historic simulation model with UC Davis. The task
4 is on-going. We do have some initial runs made,
5 some initial analysis that Staff will be reviewing
6 and we will bring it up to public review in a
7 short while, in a short time frame.

8 Last, but not least, I do not want to
9 forget the spreadsheet tool that are so essential
10 in our analysis and make our lives a lot easier
11 some times. Statistical estimations, supply/cost
12 curves that we do off line before we feed it to
13 the model, and then there are other analysis and
14 models that we use on a spread sheet to take the
15 model results and actually convert it to a price
16 projection and analysis that we publish in our
17 reports.

18 I'll take just a couple of minutes to
19 talk about each of these models. The NARG is a
20 North American Gas Model. We talked about this,
21 '89 to 2003 we were using a version where the
22 projections were done every five years. The model
23 worked for a 45 year time period. It is an
24 extremely long time frame. The idea being that
25 was to make sure in the twenty years that we use

1 to look at, we capture what happens in the market
2 from twenty to thirty years out in the future so
3 you capture some of the impacts early on.

4 This year now we are in the process of
5 using the Market Builder, which is slightly
6 different version based on the same concepts of
7 the NARG. It is a window-based, more user
8 friendly than the previous version, so it helps
9 the Staff to turn things around at a faster pace
10 from an ocean liner. Hopefully, we will get into
11 a smaller boat. It make take a little more time
12 for us to convert it to a speed boat, but we will
13 try and get there.

14 Basically now, the big change though
15 that I want to bring out here from the DOS based
16 model that we used to use in five year increments,
17 in this model we are looking at year by year
18 numbers. So, right from 2000 to 2015 we go on an
19 annual basis, and then from 2015 to 2025, we go
20 every two years. From 2025 to 2045, again, trying
21 to cover a 45 year period, we do it every five
22 years.

23 While we are still capturing what we
24 need in those long term analysis, we are trying to
25 make sure that the year to year picture for the

1 next decade at least, is going to be represented
2 well. It makes a very big difference in the final
3 result because in the five year increment, all we
4 had to do was interplay between two values. That
5 used to give us this straight line and very linear
6 type of a project, which did not really set very
7 well with a lot of the analysis. Hopefully, the
8 annual results will provide a little more meaning
9 and a little more attention to the type of
10 analysis that we are conducting.

11 Of course, there is significant amount
12 of data base that needs to be upgraded on a
13 continuous basis. We were looking at the NARG, we
14 are looking at Supply, that is the place where the
15 gas is produced. Then we have Transportation, the
16 pipeline links, which link the supply to the final
17 end user demand.

18 We have over 400 nodes in this model.
19 It is a pretty complex model. It tries to
20 calculate the market clearing prices and
21 quantities at every point in time at every node in
22 the model. Finally, that is how we get into a
23 generalized equilibrium result on prices and flows
24 coming out of the model.

25 Finally, the transportation links that I

1 am talking about. They are either single
2 pipelines, or they could be multiple pipelines put
3 into a single corridor. The idea being that if
4 you have a large amount of pipelines going from
5 one supply region to a demand instead of trying to
6 model five or ten different pipelines, you can put
7 them all together into one single representation.

8 As far as California and most of the
9 western states are concerned, we try and model the
10 individual pipelines just to make sure that we can
11 address the supply source issues better and make
12 sure that we capture the impact of changing
13 capacities and constraints on different pipelines.

14 The last point here, we determine the
15 equilibrium price and quantity for each time
16 period that we just covered.

17 This is the NARG Model. It is a lot
18 more complex than what this picture shows. We
19 have been changing things. I want to point out
20 that we are having significant changes made in the
21 L & G inputs. We are having several L & G
22 potential points on the West Coast in California
23 and in Washington/Oregon. We have also enhanced
24 the number of L & G terminal capabilities that
25 could come into place in the future on the West

1 Coast, East Coast, and the Gulf of Mexico Coast.

2 This is the short-term model that I
3 mentioned earlier. No, this is the end user price
4 projection. What we do is we take the results of
5 the North American gas model which gives us our
6 prices. It gives us the California border prices.
7 Then we take that into several spreadsheets which
8 look at the utility revenues, the cost allocation
9 processes, information that we get out of the BCAP
10 and GRC filings of utilities with CPUC.

11 We look at California Gas Report which
12 is published by the utilities. We look at margin
13 requirement by each of the utilities, and then add
14 to that irregularity and other surcharges that do
15 apply.

16 Finally, with that, we come up with the
17 end user retail price projection for each of the
18 market sectors in California. This is done only
19 for California. The only other changes for the
20 western states to suit the electricity analysis we
21 developed the power generation prices for each of
22 the different regions in the WECC regions.

23 This is the short-term and seasonal
24 market simulation tool I mentioned earlier we are
25 doing with UC Davis. I will skip over this right

1 now. We are in the process of conducting this
2 analysis, and we certainly have more updates later
3 on.

4 Skip this, it is the spreadsheet
5 analysis that everyone of us uses.

6 What are we using NARG for, long-term
7 applications, evaluation CPUC decisions regarding
8 addition of new pipelines in the past in 1990.
9 There are a whole list of other applications that
10 we have used the NARG for in the past. This
11 continues with several others in the recent years
12 in 2002 to 2003 time frame.

13 What are the assumptions in NARG. I
14 will very briefly go over some of these things.
15 Oil price is an important issue. We tried to
16 capture what is happening in the oil market. Look
17 at the DOE and EIA, oil price projections, and
18 then look at alternative for high and low priced
19 sensitivities and scenarios that we need to cover.

20 We can represent alternatives such as
21 coal, coal gasification, or other fuel fuels
22 prices in this model. We have the potential to
23 look at LNG entry.

24 Look at Alaska and McKenzie basins. We
25 have the infrastructure to address when and how

1 these pipelines can be economical, how these
2 supplies can come into the marketplace.

3 We have a significant amount of
4 resource, natural gas resources represented in
5 detail. We relied initially on the USGS, that is
6 the US agencies '95 assessment. We have now
7 converted over to the NPC case analysis where the
8 assessment are being revised over the last three
9 years. I believe that is the latest assessment on
10 the gas resources in the U.S.

11 Some more assumptions. In the past, we
12 put residential and commercial as inelastic
13 demand. The elasticity part of that demand was
14 that I had by iterating with demand assessment
15 process that we followed. In the gas model,
16 itself was basically treated as an inelastic
17 demand.

18 For the power and industrial, we still
19 had fuels which incapacibilities to look at what
20 happens depending on the economics of natural gas
21 price versus alternative fuel prices.

22 The transportation here what I mean is
23 the pipeline capacity, rates, and other factors.
24 They are always updated on an on-going basis in
25 the model.

1 We have improved the LNG analysis
2 significantly in this round of analysis to look at
3 not only the points of entry into the US, but also
4 to look at where this LNG is going to come from,
5 what the tanker rates are, etc. etc. So, we are
6 adding a significant amount of detail on that
7 sector.

8 This represents a different demand
9 regions that we have identified here. We started
10 off with basic regions followed by US DOE. On the
11 western states, we have gone into a greater detail
12 to spread them out state by state and sometimes
13 interstate regions.

14 This is to make sure that we capture the
15 detail on gas consumption in different regions and
16 also make sure that the supply pipeline and demand
17 linearity is maintained, otherwise we may be
18 projecting a lot of flows on one pipeline where
19 there is the actual gas flow may be on a different
20 pipeline.

21 This talks about the supply regions that
22 we have assessed on the western side or the NPC
23 resources. Of course, we do have supply regions
24 in the other eastern part of the US, Mexico, and
25 northeastern parts of Canada. This is just a

1 sample of how we address these different supply
2 basins.

3 In each basin, we do look at the
4 different technologies, the different depths, and
5 therefore, we try and capture the essence of what
6 potential supplies could be. Again, I want to go
7 back to the point of uncertainty, which is
8 addressed in various ways through sensitivities
9 and scenarios.

10 Talk about supply basins. We are using
11 the NPC's latest assessment. We used to have 96
12 cost curves, and now we have 253 total number of
13 cost curves in the model, which looking at it in
14 greater detail and trying to break these supply
15 regions out by cost and region.

16 This slide just basically sums up the
17 different parameters we look at in terms of
18 demand, supply in the infrastructure. I will skip
19 over this slide for any questions later on.

20 Once we have done the data check, we
21 have looked at the pipeline routes, the numbers,
22 etc., we start looking at assumptions of going to
23 a reference case. It could be treated as a mostly
24 likely, it could be treated as a business as usual
25 case. The difference in how we want to interpret

1 the reference case.

2 These assumptions, once made for the
3 reference case are key drivers which drive our
4 price friends. The major variables, already we
5 have been through, so I will skip over that point.

6 Once we have a reference case, we are
7 really not done because the uncertainty in the
8 market place really starts plaguing us at this
9 point. We need to address what can happen if some
10 things did not occur the way we thought it would
11 in the reference case.

12 We create some high and low price
13 bounds. What we do here is try and look at
14 variables that can either increase the price or
15 decrease the price of natural gas. So this way,
16 we get a boundary of price ranges. It is our
17 belief that these two trends on either side of
18 plausible, there is prices can reach these two
19 different points, but they are not sustainable
20 because the market behavior starts to take action
21 when either prices drop too much or go too high,
22 and you will get the cyclic behavior we have seen
23 in the market place.

24 Basically, the high and the low price
25 range over reach the (indiscernible) can be

1 obtainable in the future.

2 Finally, once we have identified this
3 range, then we start looking at scenarios and
4 sensitivities to actually some far out issues as
5 to what can happen in the market place, what are
6 these different emerging technologies or market
7 behaviors that can take us into a different
8 realms.

9 So, we address through scenarios and
10 sensitivities are used to define which are the
11 variables that really need to be tested in
12 scenarios.

13 I'll skip over this slide and take up
14 any questions later on.

15 Concerns identified with the model.
16 This is something that we don't do on a yearly
17 basis in every model user group meeting and
18 otherwise. We usually look at long-term issues.
19 Now we are trying to do both, how to address long-
20 term as well as a short-term.

21 The two things are very different, so
22 the models may not be the same. So, we are trying
23 to address some of those issues.

24 I mentioned the next point, that we have
25 changed from a five year increment to annual

1 increments now.

2 Explicit drilling technology is not
3 considered in the NARG, that is off-line, for
4 example the NPC analysis covers the essentials of
5 drilling technologies and what happens to
6 resources and to costs. So, that is not built
7 into the model.

8 Finally, demand in this NARG is an
9 input, not an endogenous function that is
10 developed. So, we go to the demand that is spent
11 in the electricity office for California and EIA
12 for other input that we need as far as the demand
13 is concerned.

14 I just want to spend a few minutes on
15 the techniques to be implemented in this round.
16 Forget the first point, I mentioned it three times
17 all ready.

18 Resource data is '95 assessment of USGS,
19 that has been changed now to the NPC assessment,
20 which has certainly made a very big difference.

21 The demand issues, I think the most
22 critical one we will be having a presentation
23 later on by Ken Medlock to address this particular
24 issue.

25 We used to have inelastic on the

1 residential, commercial, and small industrial, and
2 now we are going to represent the elasticity in
3 the market place. We are developing the necessary
4 inputs and the changes in the model to get that
5 task done.

6 We will in the future be analyzing and
7 developing a process by which we can actually
8 start addressing short-term markets and
9 seasonality.

10 The second to the last part of my
11 presentation here is the integrated need. This
12 chart just describes where we need to integrate
13 between the different offices at the Commission.

14 It is a complicated process, but we
15 certainly will do these things to insure that
16 there is consistency in our analysis. I will take
17 up any questions on that later on.

18 Finally, now I will call Dave Vidaver to
19 come and talk for five minutes on the electricity
20 issues that do interact with the gas market place.

21 MR. VIDAVER: Good morning. Five
22 minutes? Good, I'm glad I've been limited. That
23 is Vidaver, V-i-d-a-v-e-r.

24 I feel an overwhelming urge to tell the
25 Commission that my client was no where near the

1 scene of the crime.

2 Jariam has tasked me with explaining to
3 you how gas demand for electric generation is
4 estimated by the Commission. It is of reasonable
5 importance because it is the most volatile sector
6 of gas demand going forwards.

7 We use global energy solutions markets
8 and model to do this. According to everybody but
9 its competitors, it is the industry standards. It
10 is used by PG & E, Edison, the San Diego Gas and
11 Electric. I believe it is also used by the
12 consultants which advise SERS.

13 It is a fundamentals model which
14 requires inputs regarding the individual
15 components of the WECC electrical system. This is
16 going to be a very broad overview because I only
17 have five minutes.

18 Those components are transmission paths,
19 electricity demand, and individual generation
20 resources. The model has an hourly time set
21 meaning that assimilates the operation of the
22 system every hour over the planning period or in
23 the case of the IEPR analysis, about 90,000 hours.

24 The model first divides the WECC into 25
25 transmission zones based on what we know about

1 congestion across transmission paths, across the
2 WECC. We assign the transfer capability between
3 zones based on WECC path ratings. The vendor
4 provides us with losses on each paths and wheeling
5 charges or the cost of moving power along those
6 paths.

7 So, what we effectively have here is how
8 much power can be moved between transmission zones
9 and what it costs both in kind and currency to
10 move power between zones.

11 The modeler inputs the estimated annual
12 peak and total energy for each utility for each
13 year of the planning period. Most of this data is
14 garnered from FERC filings FERC 714, the vendor
15 assists us in this regard.

16 For California, we use the CEC forecast
17 for estimating annual peak and total energy for
18 each of the utilities. That energy is apportioned
19 across every hour of the year using historical
20 hourly values or load shapes from 1993 to 2003.

21 We have a synthetic load shape, which
22 represents a typical year smoothing out the
23 unusual observations from the previous ten years.
24 I believe the peak is preserved, and the load
25 factor is preserved. In sum, we come up with a

1 typical year.

2 The energy for each utility is
3 apportioned to each of the 25 transmission zones.
4 In some cases, this is a very simple task. For
5 San Diego Gas and Electric, for example, it is
6 quite easy. For Edison, as we have modeled the
7 transmission in SB15, it is very easy. For some
8 utilities it is a little bit harder. PG & E has
9 resources in the San Francisco transmission zone
10 as well as in ZP 26, so PG & E's peak and energy
11 has to be apportioned across three transmission
12 zones.

13 Someone like Pacific Corp who operates
14 in four or five states, their energy has to be
15 apportioned across even more transmission zones.
16 The vendor provides us with that information.

17 Finally, we input the operating cost and
18 efficiency characteristics in each existing and
19 projected future generation unit. This includes
20 fuel use per MWh or their unit's heat rate.

21 The cost of the fuel, so we input fuel
22 price forecasts whether they be the Commission's
23 gas price forecast, which has to be apportioned
24 over the models representation of the pipeline
25 system or a coal price, a set of coal price

1 forecast developed by the vendor.

2 Each unit is characterized also in terms
3 of its technical potential and its operating
4 constraints, minimum and maximum operating levels,
5 outage rates, minimum up and down times, ramp
6 rates, several other variables which determine how
7 quickly a unit can be made available, how quickly
8 it can adjust its output, and what the
9 implications are of shutting it off.

10 Each of these units is assigned to a
11 transmission zone, so when all is said and done,
12 you know in each transmission zone what load there
13 is, what generation there is, and how much power
14 you can move between zones, and how much it costs
15 to do so. The model then simply dispatches all
16 these units in the least cost dispatch for every
17 hour for a ten year period. We have a gas demand
18 forecast when all is said and done.

19 PRESIDING MEMBER GEESMAN: When you make
20 the assumptions on a unit by unit basis, you are
21 doing that across the WECC or California only?

22 MR. VIDAVER: Yes. We have one staff
23 member who spends about three quarters of his time
24 looking at resources that have been put forth
25 throughout the WECC. We then sit down and decided

1 which of those meet the threshold criteria for
2 inclusion in the model.

3 Once you get out beyond about 2007, you
4 are starting to guess, so you need to use rules of
5 thumb regarding capacity margins that are going to
6 exist in each area, what types of units are going
7 to be built in each area, whether they are gas or
8 coal.

9 If they are gas, whether they are
10 combined cycles or peakers. You need to make
11 assumptions about how much renewables are going to
12 be located in each area and what the capacity
13 factors of those technologies are and how the
14 energy is profiled over the course of a day, a
15 season, and a year. It is a lot of user
16 assumptions that go into this.

17 PRESIDING MEMBER GEESMAN: You derive
18 those internally, the vendor doesn't provide
19 those?

20 MR. VIDAVER: Correct, we don't rely on
21 the vendor at all for any of that information.
22 They do provide their projections regarding what
23 is going to be built in California and elsewhere
24 over the next one to three or four years. We pay
25 very little attention to that. It is just one of

1 the minor inputs in our decisions in what we will
2 be built.

3 PRESIDING MEMBER GEESMAN: You
4 accomplish the rest of it all for three quarters
5 of a person?

6 MR. VIDAVER: No, what we do is we track
7 the out of state generation using about some where
8 between .5 and .75 per watt, we then sit down with
9 that person and talk about what of the units that
10 have been coughed up anywhere from fully permitted
11 and under construction to something that a press
12 release has been issued for, and we sit down and
13 decide how much capacity is of that, what is
14 likely to be built. Looking out a bit farther,
15 how much capacity is going to be needed and
16 actually built in the longer run in each area.

17 PRESIDING MEMBER GEESMAN: If there is
18 anybody from the Department of Finance in the
19 audience, this is one of the greatest economies in
20 state government. It is a lot of work for three
21 quarters of a person here.

22 MR. VIDAVER: I will tell Richard Jensen
23 who does this, that you think he is doing a great
24 job. At least I think that is what you said. I
25 guess we will know in twenty years when we see how

1 our point goes.

2 The key drivers of EG gas demand, the
3 things that we should pay attention to are
4 electricity demand. This is to the extent that
5 gas is on the margin. In the short run, any
6 variation in electricity demand is going to change
7 gas demand, and more or less gas demand only. It
8 is not going to change the use of coal or
9 renewables.

10 In the longer run, the impact of
11 electricity demand is based on what you are going
12 to assume about the technologies that are going to
13 be used to generate electricity going forward.

14 If you assume higher levels of
15 electricity demand in long run and that some of
16 the base load energy needs in the WECC are going
17 to be met by coal, obviously changes in
18 electricity demand are going to influence not only
19 natural gas demand but coal demand as well.

20 Relative fuel prices are less important
21 in the short run because gas is just so darn
22 cheap. Excuse me, so darn expensive relative to
23 coal fire generation.

24 Right now I believe coal is going about
25 \$60 which comes out to about \$2.40 per MMBTU. If

1 you can find gas for \$2.40 per MMBTU, you
2 obviously have a rather dated long-term contract
3 in your portfolio.

4 The price of gas actually has little
5 effect on total gas demand on the part of electric
6 generators in the short run. In the longer run,
7 obviously, the price of gas is going to influence
8 what is built and retired going forward.

9 What will be built going forward is
10 dependent upon policies, for example carbon tax or
11 the opening up of lands for natural gas
12 exploration.

13 Expectations on those policies which
14 staff has no insight at all regarding and fuel
15 prices. In a nut shell, what Staff assumes is
16 built going forward is based on their best
17 professional judgement. Therefore, it must be
18 vetted publicly.

19 What is retired going forward influences
20 gas demand, but it is really not the retirements
21 of aging gas plants that influence anything. It
22 is the retirement of coal plants. If we retire a
23 35 year old base load coal plant and replace it
24 with a natural gas plant, we have increased gas
25 demand.

1 If we retire a 35 year old steam turbine
2 in Southern California, we are going to replace it
3 with a peaker that basically consumes the same
4 amount of gas on the whole.

5 Old gas plants don't really retire their
6 capacity factors, just drop to zero. If we leave
7 them in the model, they just simply don't run.

8 What many people overlook is that
9 relative gas prices have an influence on the
10 geographic dispersion of EG gas demand. The model
11 we use is very very sensitive to the relative gas
12 prices in let's say California and Arizona. If we
13 tweak the gas prices in Arizona a couple of cents,
14 we can actually get generation to shift from
15 California to Arizona in plausibly large
16 quantities. That means our modeling of those
17 relative gas prices is from the point of EG gas
18 demand much more important than the actual gas
19 price level in the long run.

20 I think my five minutes are up.

21 PRESIDING MEMBER GEESMAN: You have set
22 up my question for Jariam quite well. The 400
23 nodes?

24 MR. GOPAL: Yes.

25 PRESIDING MEMBER GEESMAN: How do we

1 update the assumptions for each of those nodes?

2 MR. GOPAL: The 400 nodes represent
3 supply, transportation, allocations, and demand
4 nodes. There are some allocation nodes, for
5 example, that are normally apparently an
6 assumption is not needed.

7 All the demand nodes are updated on a
8 regular basis. Every time we run a new reference
9 case, we go and update the entire set of demand
10 nodes.

11 Basically, that is the information that
12 we collect from DOE, EIA, a variety of Canadian
13 organizations, maybe some publications, and maybe
14 Houston University for Mexican demand assumptions,
15 and of course the California numbers, the numbers
16 from the California from the CEC.

17 PRESIDING MEMBER GEESMAN: What about
18 the supply assumptions and price assumptions at
19 each of those nodes?

20 MR. GOPAL: The supply cost price and
21 quantity assumptions are made whenever there is a
22 very big change in say for example going from USS
23 to NPC, it is a very major task. It takes us a
24 little bit of time to go through and change all
25 the curves, but it is very likely that through

1 doing one cycle, we may go and change some of
2 these curves specifically based on how the model
3 behaves and what we hear from different producers
4 in different regions.

5 PRESIDING MEMBER GEESMAN: That is not a
6 vendor provided service?

7 MR. GOPAL: It's not vendor provided.
8 We strictly make sure that we develop the
9 assumptions based on communications with parties
10 and input that we get at workshops and other
11 places.

12 PRESIDING MEMBER GEESMAN: You do that
13 on what you perceive as an as needed basis rather
14 than a regular cycle?

15 MR. GOPAL: We do address in every
16 single, but specific ones may be updated when we
17 get additional information. We look at the entire
18 supply curves every cycle, we provide it to the
19 participants, to the producers that have been
20 interested in turning over workshops. We post it
21 on our website so there is a broad circulation of
22 the information.

23 MR. MAUL: Commissioner, if I could just
24 clarify that when you say "vendor purchased", we
25 had been using the USGS data base on supply

1 quantity and cost curves associated with each of
2 the basins. That data was vintage 1995 and had
3 not been updated for many years. Just last year,
4 the National Petroleum Council went back and did a
5 complete assessment and actually in much more
6 detail than the previous USGS assessment.

7 They did work with USGS, and we have
8 purchased that data, so when you say vendor
9 provided, we actually bought the data base from
10 the National Petroleum Council, which is the same
11 data base now being used by US Department of
12 Energy in USGS. So, we have a consistent data
13 base throughout the US, and it is the most recent
14 available on a comprehensive basis.

15 As Jariam noted, when we get information
16 on individual basin because something has caused
17 it to be updated, then we will use that individual
18 update, but we only do a major update when the
19 national data is updated.

20 PRESIDING MEMBER GEESMAN: Thank you.

21 COMMISSIONER BOYD: Basically, what we
22 are talking about in the last few minutes is one
23 of the basics of theorems of modeling I guess. It
24 is that assumptions are everything or the way it
25 used to be put is to put garbage in is garbage

1 out. The model is the machine that grinds data
2 assumptions. The assumptions are everything, and
3 that's -- you get real quick to the crystal ball
4 stage of dealing with your future. It is nobody's
5 fault, that is just a fact of life. Dealing with
6 assumptions is just virtually everything. You can
7 make the machine correct ultimately.

8 MR. GOPAL: I can give you two examples
9 of how we actually made some changes to very
10 specific regions. One was when coal, methane, and
11 the four corners, it says (indiscernible) basin
12 supplies were coming on. The general information
13 that we obtain from a variety of sources, like DOE
14 and other sources, indicated that there would be a
15 certain extent of coal being maintained for
16 penetration in the market place.

17 We spoke to producers in this basin, we
18 spoke to the state of New Mexico where we had done
19 a specific amount of analysis and we changed the
20 resource estimates and the costs for the critical
21 coal being maintained.

22 The second case was I think '95 or '96
23 when suddenly the unconventional resource base
24 production in the Rocky Mountains seemed to really
25 explode compared to what was assumed in previous

1 years.

2 So, suddenly our model kept telling us
3 that you need one heck of a lot of gas from Rocky
4 Mountains, and that raised a lot of questions.
5 When we hired a consultant to actually analyze
6 this particular resource base very thoroughly. We
7 had a lot of information that we obtained from him
8 in that study, and those changes were made in the
9 data base.

10 So, those are the type of assessments
11 that we do a regular basis during each cycle.

12 MR. MAUL: Commissioner, if I could
13 follow up on two key points you both have made.

14 One is that assumptions are everything
15 and also the concern about timeliness it takes,
16 how nimble we are and how agile we are.
17 Unfortunately certain kinds or groups of
18 assumptions can't be updated very fast. As I
19 pointed out, the supply area. Because of that, we
20 understand there is some uncertainty in the output
21 if the input is becoming stale, so that really
22 drives our interest in doing sensitivity analysis
23 and scenario analysis so that we can try to
24 bracket some of the uncertainties or the freshness
25 of the data by looking at various assumptions that

1 we put in to it that might try to capture the
2 range of uncertainty of a single assumption going
3 in and its affect on the output. That is why we
4 have highlighted that in the presentation today.

5 PRESIDING MEMBER GEESMAN: I think that
6 is an important point to keep in mind and
7 certainly Dave's comment about the importance of
8 regional gas price differences backing into the
9 generation sector, particular as you get into
10 those out years with our half to three quarter of
11 pW is estimating is what is going to get built and
12 what is not.

13 It is likely to have fairly significant
14 consequences in California as it relates to
15 providing adequate electricity supplies.

16 MR. GOPAL: During the last cycle, what
17 we did was we actually made several discussions
18 with the utility companies and the electricity
19 office and the gas office to look at how these
20 issues were treated in the California Gas Report
21 with regard to gas demand for power generation.
22 So, we tried to make sure that there was
23 consistency in the analysis.

24 PRESIDING MEMBER GEESMAN: I would
25 suggest to you that all of this particularly as it

1 relates to Southern California, last summer and
2 next summer appear to have either gotten it wrong
3 or not sufficiently appreciated the magnitude of
4 uncertainties involved and how best to address
5 those uncertainties. It is a field far beyond
6 natural gas forecasting obviously, but it is one
7 of the principle obligations of this Commission to
8 try and identify where those uncertainties exist
9 and how best to mitigate the risks associated with
10 it.

11 MR. GOPAL: We can certainly do that.

12 MR. MAUL: Any more questions? For the
13 last 45 minutes, we have been having a
14 conversation, a dialogue with Staff and
15 Commissioners, we would like to refocus this now
16 to the audience. We would like to have more of a
17 dialogue with audience members and the
18 Commissioners and ourselves, more of a dialogue in
19 workshop format.

20 The first person that we have on the
21 agenda for discussion is Hillard Huntington, who
22 is Director of the Energy Modeling Forum at
23 Stanford University and has done quite a bit of
24 work with looking at modeling in general in a
25 variety of areas, not only natural gas, but other

1 energy forms as well.

2 While Hill is coming up to make his
3 presentations, I'd like to just make two more
4 logistical announcements for folks who are on the
5 conference call. Is anybody else having any
6 difficulty seeing the presentations on the CEC's
7 website?

8 It sounds like we are okay then.

9 MR. FORD: I would like to check in at
10 this point. My name is Andy Ford. I am at
11 Washington State University.

12 MR. MAUL: Oh yes, Andy, how are you
13 doing?

14 MR. FORD: Good. I'm listening on the
15 conference phone, and I am at the website, and it
16 says that due to technical difficulties, the
17 material isn't being broadcast.

18 MR. MAUL: Oh, wonderful. Let me give
19 you a phone number you can call and see if we
20 can't get that straightened out. On our web team,
21 you can call Nancy Hasman. Her phone number is
22 916-654-4987 and hopefully that can straighten
23 that out for you. Unfortunately, we are in a
24 different building than they are, so you can get
25 them as quickly as we can.

1 MR. FORD: Is it intended something like
2 a set of power point files --

3 MR. MAUL: Yes. Normally, we would be
4 posting them up there so they are either pdf or
5 power point files that you can access with the
6 various folks so you can see exactly what we are
7 seeing here in this room.

8 MR. FORD: Good. I'll give her a call.

9 MR. MAUL: If it is not right now, it
10 will be posted later today, and obviously you will
11 have access to it in the archives.

12 MR. FORD: Thank you very much.

13 MR. MAUL: Anybody else having
14 difficulty on the phone? For anybody else who is
15 listening and not knowing what is going on, this
16 is the California Energy Commission's 2005
17 Integrated Energy Policy Report Workshop on
18 Natural Gas Modeling.

19 For folks in the audience, if you don't
20 know where things are, probably the most critical
21 thing is the restrooms are literally across the
22 hall.

23 Any more questions? Yeah, Roger.

24 UNIDENTIFIED SPEAKER: Are you fielding
25 in just clarification questions for Jariam if I

1 could.

2 MR. MAUL: Yes, go ahead.

3 UNIDENTIFIED SPEAKER: On slide eleven,
4 he referenced predictions of different locations
5 within California. Would that mean what
6 (inaudible)?

7 MR. GOPAL: We do --

8 MR. MAUL: Can you repeat the question
9 for those on the phone?

10 MR. GOPAL: Is this the third bullet?

11 UNIDENTIFIED SPEAKER: You mentioned it
12 while you were presenting that slide. That is
13 when (inaudible).

14 MR. GOPAL: Basically the question was
15 whether we do look at price differentials between
16 regions, such as PG & E City Gate and the border
17 prices.

18 UNIDENTIFIED SPEAKER: The basis
19 differential from Henry Hub to --

20 MR. GOPAL: Okay. There are several
21 ways we address this issue. One is we have a
22 model predicted value of city gate price. That
23 sort of accounts for what happens between the well
24 head and city gate. Between city gate and
25 different regions, especially in California, and

1 where we have specific power generation prices
2 that are being used for the western states, we do
3 look at what this model says versus what the
4 actual basis differentials are today.

5 Of course, what happens in the future is
6 something that we have to try and estimate. That
7 is one of the issues that we do address on that
8 basis.

9 UNIDENTIFIED SPEAKER: One other
10 question when you were speaking of slide 23 and
11 high and low price bounds relating to the oil
12 markets, are you doing (indiscernible) between
13 natural gas and (indiscernible)?

14 MR. GOPAL: The question relates to how
15 do we deal with oil prices and gas prices
16 equivalency when we are looking at the high and
17 low bounds and/or the scenarios or we just looking
18 at sensitivities on oil prices.

19 In the model, we actually do represent
20 the crude oil price, but we have functions where
21 it is going to convert this crude oil price into a
22 gas equivalent price to determine what the
23 particular market is. So, in California and once
24 upon a time, we used to have low sulphur fuel oil,
25 in other regions, we have residual fuel oil, or a

1 No. 2 fuel oil, or distillates, and we look at
2 historical prices of these products that compete
3 in the electricity generation market.

4 Looking at the historic maybe the last
5 five years of numbers, we determine how the crude
6 oil price has to be converted to be an oil
7 equivalent on a dollar per the MCF basis.

8 PRESIDING MEMBER GEESMAN: Is that
9 implicitly assumed that the degree of fuel
10 switching going forward stays the same as it has
11 been the past five years?

12 MR. GOPAL: No, the fuel switching will
13 be determined by the model based on the gas and
14 oil prices. The oil prices is (indiscernible) and
15 fixed and that is one of the issues that we try to
16 look at in the analysis to see how much of
17 switching. Is it reasonable or is it
18 unreasonable. We then talk to different
19 organizations, for example, the Department of
20 Energy and what their assumptions are.

21 We then talk to the industry on that to
22 see if something of that nature is reasonable.
23 The big question there is the oil price or the
24 consequential distillate or fuel oil price. We
25 try and look at --

1 PRESIDING MEMBER GEESMAN: You assume
2 then that the environmental restrictions stay the
3 same over your forecast period?

4 MR. GOPAL: In most cases, yes, over the
5 forecast period. In specific case, it is assumed
6 to be the same.

7 UNIDENTIFIED SPEAKER: This is exactly
8 where I was headed, the nodes, the substitution
9 factor and the trade press over the last two or
10 three years is saying that shrinking, and you
11 can't count on that any longer.

12 MR. GOPAL: Between regions, we do look
13 out how the one model conditions. For example, in
14 California, we have completed avoided fuel
15 switching.

16 PRESIDING MEMBER GEESMAN: I guess I am
17 more focused on the mid-Atlantic states and some
18 of the other regions in the country where you are
19 seeing a fairly drastic change in the degree of
20 fuel switching. I guess I would be hesitant about
21 being able to make projections too far out into
22 the future of the current mix staying the same,
23 subject only to price variation.

24 MR. GOPAL: We assume the mix to be only
25 the first year and then the model determines how

1 it changes by price.

2 PRESIDING MEMBER GEESMAN: Right.

3 MR. GOPAL: We will certainly keep that
4 in mind when we look at the results next.

5 PRESIDING MEMBER GEESMAN: It may be
6 worthy to talk to EPA about their estimates of
7 future clean air act driven restrictions elsewhere
8 in the country.

9 MR. PEETAC: Jariam this is Kevin Peetac
10 with EPA. I have a follow up question on your oil
11 prices, and if my understanding that your oil
12 price -- that you were assuming a single oil price
13 for a region, or you assuming a basket of oil
14 prices, this combination of residual and
15 distillate prices, and different quality fuel
16 prices?

17 MR. GOPAL: The model assumes one single
18 refinery acquisition crude oil price for the US as
19 a whole and another set of prices for Canada.
20 After that point, as it reaches different market
21 regions, the prices are (indiscernible) to
22 represent the distillates or number of fuel oils
23 in the different markets. There is only one fuel
24 price per demand region.

25 MR. PEETAC: Okay, thank you.

1 MR. GOPAL: I think, Leon, did you have
2 a clarification on the EPA on regulations?

3 MR. BRATHIWAITE: No, I was going to say
4 that, Commissioner, just what Jariam said, we do
5 have the flexibility that if we foresee any
6 changes in our environmental laws or regulation or
7 rules, we do have the flexibility within the
8 modeling to include those things.

9 Let's say in the mid-Atlantic we see ten
10 years out that rules will forbid the
11 (indiscernible) particular oil or fuel or anything
12 like that, we have the flexibility to include
13 that.

14 If, for instance, renewables and some
15 mandates and some place, we can also take care of
16 those (indiscernible), so the model has that
17 flexibility. That is the good thing about it.

18 MR. MAUL: Our next discussion is Hill
19 Huntington.

20 MR. HUNTINGTON: Thank you very much,
21 and good morning, Commissioners.

22 My role at the Energy Modeling Forum
23 over the last three or four years has been to do a
24 comparison of a lot of the different natural gas
25 models. I think that was one of the reasons why I

1 was invited to come here and talk to you a little
2 bit about what we learned.

3 Usually when I do this kind of a
4 presentation, I often emphasize a lot of the
5 details of the models and the specific kind of
6 insights that we learned. I felt that this
7 hearing would give me an opportunity to step back
8 a bit and tell you a few things that I think are
9 really important when you are talking about
10 natural gas models and things to think about as
11 you are putting them together.

12 I should say that I am talking primarily
13 about the longer term type of models because I
14 think that is first of all, that is where my
15 expertise is, and secondly, I think that is where
16 a lot of you have a lot of very important
17 decisions on siting things, pipelines and LNG
18 facilities and so forth. That is a key issue that
19 you should be thinking about.

20 With that, I will just take a few
21 minutes to go through a few points. I've kept it
22 fairly short, so that you can ask questions and we
23 can steer this in directions that you think are
24 appropriate. In fact, I've called it my Top-10
25 List for Natural Gas Modeling with due respect to

1 David Letterman and all. I am not going to go the
2 reverse order like he does.

3 Maybe a little hard to read it there,
4 but it says, Prices and flows reflect engineering
5 constraints in a regulated industry. Now, we have
6 looked at a lot of different models, some of them
7 look very much like the way the NARG model looks
8 like, others have used different approaches.

9 We found that in the old way of looking
10 at natural gas markets, when it was a regulated
11 industry, we found that things like linear
12 programming approaches and other types of models
13 that did a good job of reflecting the engineering
14 constraints and primarily the engineering
15 constraints were very very important for looking
16 at natural gas markets.

17 With the new liberalization of the
18 markets, we think there is an emphasis to look at
19 the prices and flows as reflecting economic
20 opportunities.

21 That is not to say that the engineering
22 constraints are not important, but what happens in
23 the rest of the United States and particularly
24 regions that compete with California or regions
25 that might supply California are going to be very

1 very important.

2 You need a modeling system that will
3 reflect those opportunities. Also you need a
4 system that thinks about what is today's choices
5 versus what is tomorrow's choices. So, you need
6 both of those kinds of things.

7 As a result of that, there has been a
8 lot of emphasis going on in developing models that
9 have what I will call kind of a general
10 equilibrium framework in the sense that they
11 reflect these other opportunities. I think the
12 NARG-based systems are exactly like this.

13 There are a number of other types of
14 approaches that people have used and we have
15 looked at them. There are lots of different
16 programs, but it is this general equilibrium model
17 which I think people feel is particularly strong
18 for longer term issues when you are looking at
19 economic opportunities.

20 Now, this third point, I don't think I
21 will have any objections here that higher prices
22 allow producers to drill for more expensive
23 sources, and I should also add will allow
24 presumably encourage people to bring on more LNG
25 facilities.

1 What I really want to emphasize here is
2 a point that was already made that there is
3 incredible amount of uncertainty in any of these
4 assessments. You have heard the transition going
5 from USGS to NPC, that kind of an adjustment is
6 going to reflect rather substantially the kind of
7 projections you have.

8 What I often tell people is that it is
9 extremely important to think about a couple of
10 different views of the world as you are going
11 through this, and your point about uncertainty was
12 exactly the kind of thing that I would reemphasize
13 because I think if you get locked in to one
14 resource base like we did with the USGS estimates,
15 then we are going to run into that kind of a
16 problem.

17 Likewise, if we get too locked in to the
18 NPC results, I could really see at some point
19 people's changing their assessment of that. I've
20 worked with people at the Earth Sciences at
21 Stanford, and they tell me there are lots of
22 different ways of going about changing the costs
23 of looking for these gas sources. So, I think we
24 really need to represent that.

25 I would also represent or emphasize I

1 guess the importance of the LNG picture into this
2 thing. I often tell people that we model Northern
3 American natural gas, you are no longer talking
4 about just North American natural gas, you are
5 talking about a world market.

6 Again, this fourth point is pretty
7 uninteresting, higher prices will reduce natural
8 gas demand. I think many people would agree with
9 that. What I really want to emphasize here is
10 importance of going to lots of different sources
11 on this. Go to engineering estimates, go to
12 statistical estimates, get as much information as
13 you can about this.

14 I am really pleased to see that the
15 California Energy Commission is moving in the
16 direction of picking up demands that are sensitive
17 to price because I absolutely believe that is
18 the way the world works.

19 I have a few more points on this if I
20 can --

21 COMMISSIONER BOYD: Could I interrupt
22 and ask you a question about the elasticity and
23 inelasticity issue you just brought up? I mean
24 what kind of agreement exists today on this effect
25 of elastic/inelastic demand as it responds just to

1 price?

2 MR. HUNTINGTON: There is a wide
3 disagreement. If you take all of the people who
4 have commented on it, there is a wide disagreement
5 I think if you look at the results from the
6 National Petroleum Council study, their results
7 suggest that there is very very limited resources
8 unless you go out and make major changes in
9 policies.

10 I think if you were to go and survey a
11 lot of the academic community and research
12 communities who have been looking at this issue,
13 they don't find a dramatic change in the price
14 elasticity issue just in the last few years. They
15 don't think that is what is causing the high
16 prices. They think there is still quite a bit of
17 substitutability out there. It is just that most
18 of it is long term substitutability, and it is not
19 going to happen over the next few years. There is
20 no big agreement on this if you look at the wide
21 group.

22 I would like to say a few words about
23 some of the demand response. I notice that Ken
24 Medlock is on this, and he will probably talk more
25 details about this, but think of the many

1 different ways that prices can affect the demand.

2 We often think of just the piece of equipment that

3 can use either types of fuel, like gas versus oil.

4 It is true that has been shrinking, but one of the

5 reasons that it has been shrinking is that gas for

6 the longest time was a very well behaved fuel.

7 The price volatility wasn't an issue. Now it is.

8 People are starting to think about ways
9 they could trade off natural gas with other
10 sources. Even if that is constrained, there are
11 other ways people can operate.

12 One of the classic cases I think of is
13 natural gas is used in combined cycle which in
14 certain regions is a real competitor with coal for
15 base load electricity generation.

16 You have these firms that can use either
17 natural gas or can operate their coal facilities
18 more intensively. That is a degree of
19 substitution in my mind because it is a broader
20 sense. It is not a substitution between with the
21 one piece of equipment, but it is a substitution
22 between plants. So, that is another issue.

23 Even if there are constraints on that,
24 people could be substituting away from natural gas
25 use for peak load demands and towards more

1 baseload kinds of use.

2 Over time, and this is really important,
3 we've got new pieces of equipment coming in place,
4 and that gives you the option to choose the fuel
5 so you can choose a different type of fuel, and it
6 gives you the option to change fuel efficiency.

7 I also think that over time when policy
8 makers see that natural gas, if natural gas should
9 stay expensive for a long period of time, I think
10 a lot of these rules that people are making about
11 well, you can't use natural gas -- or you've got
12 to use natural gas because that is the only way to
13 go. I think people will change their view.

14 When you are looking at a long-term
15 projection, I think you have to factor in all of
16 these kinds of things.

17 Finally, there is the comment that even
18 if you don't change fuels, you are going to reduce
19 the amount of natural gas and other energy, and
20 simply you could put in more labor and capital.
21 There is also the possibility that you lose demand
22 in a region or even in the United States. Of
23 course, we really don't want to see that happen,
24 but that will happen and that will have an affect
25 on price as well.

1 For all these reasons, I think you have
2 to take a broad view of this thing and not kind of
3 sit down and say, well, I know the amount of oil
4 and gas substitution today, I go around and count
5 up the units and therefore it is more limited,
6 therefore that is the way it is going to be for
7 the next twenty years.

8 I think that is a mistake, like taking a
9 picture when the thing is really a movie, and that
10 is what you want the model for is to trace through
11 the time.

12 That is kind of what I want to say about
13 the demand. I think this issue will come up. I
14 would be very surprised if it didn't come up
15 again. I know it will in another presentation.

16 Going back to my top ten list, and
17 then -- these are the points I've already made.
18 This is also about demand. I am absolutely
19 convinced that the industrial structure, the kinds
20 of goods and services we are producing, have
21 enormous influences on natural gas demand. So,
22 that is another, again, we talked about
23 uncertainty. That is another uncertainty I would
24 spend a lot of time talking about.

25 We put together a fairly simple type of

1 analysis to look at this issue, and it was based
2 on what has happened historically, and then we
3 just looked at how the structure of the U.S.
4 economy changed, how that would influence natural
5 gas demand. In this analysis we didn't really
6 change any of the prices or anything like this.
7 This is a totally different effect.

8 What we did was took the annual energy
9 outlook which is put out by the Energy Information
10 Administration. That is basically their
11 projection, or it is their projections based on
12 the -- it is their assumptions put into this
13 simple frame work.

14 Natural gas grows. We started in 2003,
15 it grows by this blue line. We then said take
16 another case where we took the shifts -- as you
17 probably know, in the 1990's there were enormous
18 shifts going out of big heavy industry towards
19 computer oriented industries. So, we took that
20 effect out, and we just looked at what the shift
21 was like before that happened, and that is what
22 this red line looks like.

23 Then we said what if the future looks a
24 lot like what happened during much of the 1990's,
25 and we returned to that kind of a world. So, this

1 is where a lot of the heavy energy-intensive
2 industries are leaving. They are leaving the
3 United States.

4 As a result, you end up with about a
5 three trillion cubic feet difference or almost a
6 30 percent difference in the projection based on
7 what you assume about that key factor.

8 Again, I think I often caution people we
9 want to look at several different types of cases
10 and get a feel for how important this issue is
11 before we just conclude we know exactly what
12 natural gas demand --

13 COMMISSIONER BOYD: Another comment if I
14 may in the form of a question, I guess.
15 Basically, what you are saying is the net
16 difference between heavy industry and
17 manufacturing as we knew it and the advent of the
18 new electronic age which sucks up a lot of
19 electricity which drags electricity demand. Still
20 the net difference in gas consumption is that
21 dramatic change.

22 MR. HUNTINGTON: It is possible -- let
23 me focus -- this is looking at just at the
24 industrial sector. So, to the extent that the
25 commercial sector is supposed you are just using

1 more electrical equipment, we are not picking that
2 issue up, right? So, does that help clarify that?

3 COMMISSIONER BOYD: Yes.

4 MR. HUNTINGTON: This is kind of taking
5 a piece of the puzzle and figuring that out.

6 Prices are very volatile in the near
7 term. I think this is important because we are
8 talking about models that project long term
9 prices, and then we always get caught with the
10 situation, yeah, you say the price is going to be
11 \$5.00 in the year 2010 or whatever, but I am
12 looking at prices \$6.50 or so. How do I make
13 sense out of that.

14 Just to kind of get there. The prices
15 that we are picking up, we don't pick up these
16 prices moving all around like this. We certainly
17 don't pick that up in the long-term projection,
18 nor this.

19 Now it is very interesting, this
20 particular price spike was in natural gas, whereas
21 this green line here is what happens to the oil
22 price. So, natural gas shot up in 2001 without
23 oil prices shooting up, and I think we all know
24 that it was the winter peak that produced that.

25 In 2003, gas prices shot up, but so did

1 oil. In fact, if I continue this on out, we would
2 have seen that they moved rather nicely together,
3 but the point is that the volatility in the price,
4 we are not going to be picking that up. That is
5 really really important to emphasize. I think you
6 need a different set of kind of techniques to pick
7 up this volatility. Again, I think the Commission
8 seems to be headed -- I don't know the details of
9 the framework, but it looks like it is the right
10 approach to pick up some of the shorter term
11 affects.

12 That is about all I wanted to say on
13 that.

14 This is a little more complicated, but
15 it gets to the issue of what we have here and also
16 in interpreting prices. I think what is going to
17 happen I think in the longer run could look very
18 different than what we see today.

19 In the longer run, I have been amazed at
20 the role of investment and technology has, and I
21 think it could help -- I can see a certain set of
22 circumstances where we turn the price back to --
23 never going back to where we were in the '90's,
24 but it could help bring down the price path more
25 than most people expect it could. I certainly

1 could imagine a situation where it could get
2 worse. Certainly, if we have more turmoil in the
3 oil markets, it could get worse.

4 I think one of the scenarios you ought
5 to look about is the one where the price kind of
6 goes part way of where it was in the '90's and
7 where it is today. I am talking about now what I
8 will call inflation adjusted prices now because
9 that is what the models often put out.

10 This is a little complex, but I hope not
11 too bad, but if you are at all familiar with the
12 NARG model, you know that the NARG model will have
13 a supply curve, and this is this upward sloping
14 curve, so that says as the price goes up, quantity
15 increases, and it will have a downward sloping
16 demand curve where consumption increases as prices
17 actually get lower.

18 We are in a situation here. We are at
19 this price level here. Now, why can't we just say
20 that is what the future price is going to be?
21 Over time you would expect supply investments to
22 happen. The supply investment will not only shift
23 the curve out, but it will make this curve more
24 responsive over time. That is one thing that
25 could definitely happen, both in the oil and the

1 gas markets.

2 At the same time, you have the same kind
3 of thing happening on the demand side. Again,
4 investments in the demand, new technologies coming
5 on could shift the curve down and could make
6 downward pressure on prices.

7 We are not really looking at a snapshot,
8 we are looking at this almost like a movie, going
9 from this point to this point. This is what these
10 equilibrium models are really trying to tell you.

11 Now I have painted it as a picture,
12 prices falling. I just to emphasize again we
13 could obviously get into a situation where prices
14 could have continued pressure on it, depending on
15 our assumptions. I think that is very important
16 to emphasize.

17 PRESIDING MEMBER GEESMAN: What do you
18 think the length of that price cycle might be?

19 MR. HUNTINGTON: Oh, yeah, I'm saying
20 you would start seeing some of these things in
21 about five years or so. I don't think you are
22 going to see things happen dramatically before
23 that.

24 There is kind of a fine line there. It
25 is definitely longer than the next few years, but

1 you should definitely see it well before the ten
2 year framework. It is just kind of five years is
3 a guess.

4 That goes back to my previous comment.
5 Today's prices are a poor predictor of tomorrow's
6 price. I was going to put in some fancy slides in
7 there about how people have done all this kind of
8 analysis, but what they come up with, is the
9 conclusion is, if you know what today's price is,
10 it often does not help you very much knowing what
11 tomorrow's price is. It also doesn't really help
12 you even over the long term knowing what those
13 prices are.

14 When you hear that that the spot price
15 is "X" and you are looking at a long term price of
16 "Y", it doesn't automatically say that model --
17 what I would say as a rejoinder on this, you
18 should be asking the modelers then, tell me the
19 story that goes between the short run and the long
20 run, and then I will know whether or not I should
21 believe you. The two don't have to be equal to
22 each other.

23 The other issue is sometimes people look
24 at natural gas prices and they immediately say
25 that the financial markets are expecting a totally

1 different price than what is coming out of these
2 models. This really concerns a lot of people.

3 Now I don't want to get into a big
4 discussion of whether financial markets are a good
5 way of looking at future prices. I think there
6 are believers and there are disbelievers.

7 Let's say for a minute that we really do
8 want to have our prices coming from the models
9 looking something like what is coming out of the
10 financial markets. What I did was I did a fairly
11 simple analysis. I put everything in terms of
12 what I call nominal prices, which is the prices
13 the layman sees. I am not talking about inflation
14 adjusted prices. I took the model results in some
15 of our studies, and I converted all those prices
16 to nominal prices. I made them in current
17 dollars, and then I simply did a comparison with
18 what the financial markets were telling me a few
19 months ago about what was happening in the very
20 long run.

21 Then I simply plotted up the results
22 where I've got these prices I just talked about
23 here from zero to \$7.00, and then I put in -- this
24 got all goofed up, but these are EMF numbers,
25 these are different model numbers here. I decided

1 I wouldn't confuse everybody by putting model
2 names.

3 Each one of these are different
4 projections coming out of the model for the year
5 2010. That is what the bars are. This line here
6 is what the future price would imply.

7 The market is very thin out here when
8 you go out this length, and you can sort of say,
9 well, big deal, but it is sort of a continuation
10 of the shorter term trends which I think people
11 have a little more faith in.

12 It shows that these models are not
13 terribly far off. One of the key differences is
14 that they often report their results, and the
15 difference is the future prices are in terms of
16 the nominal dollars and the model results are
17 reporting things in real dollars.

18 What happens over here is this is the
19 annual energy outlook which is the Energy
20 Administration, and this is their old projection.
21 It is the 2004, they seem to be a little lower
22 than others. Then I put finally on this, the
23 line, the NPC reactive policy case. This is one
24 of the base cases used by the National Petroleum
25 Council, and their price projection was quite a

1 bit higher.

2 I am not sure what I pull out of all
3 this, except that a lot of the models seem to be
4 coming in. Their numbers are not unbelievable. I
5 could certainly see them explaining their results
6 saying this is why we are different from the
7 future markets. The NPC result seems a little
8 high to me, but that may be due to the assumptions
9 they built into that particular case.

10 I don't really find these that these
11 prices coming out of the models are
12 dramatically -- I don't look at them and say, wow,
13 these things are really low or whatever. I think
14 they roughly -- they paint a view of the world
15 that is certainly possible, and I will just leave
16 it at that.

17 PRESIDING MEMBER GEESMAN: Let me ask
18 you on that. I am going to guess you mixed a fair
19 number of vintages in those forecasts --

20 MR. HUNTINGTON: Yeah.

21 PRESIDING MEMBER GEESMAN: -- made over a
22 period of a number of different months?

23 MR. HUNTINGTON: Yeah.

24 PRESIDING MEMBER GEESMAN: You took a
25 single point for your futures price. Is there a

1 problem with that?

2 MR. HUNTINGTON: Here is the problem.

3 Many of the prices are higher. Many of the future
4 prices are higher. Tomorrow the prices tend to
5 look fairly high, and they don't really grow much
6 with inflation. So, I would think there is a
7 bigger difference between the models. If you are
8 looking at the next year or two, there is a big
9 difference between the model projections and the
10 futures prices.

11 If you view these things are telling you
12 something about the longer run, then they seem to
13 be closer as this picture indicates.

14 If I did the same picture for say 2005
15 or 2006, you would see a bigger difference on
16 that. Does that answer that question?

17 PRESIDING MEMBER GEESMAN: It does. Do
18 these markets typically find themselves in
19 backwardation?

20 MR. HUNTINGTON: Sometimes.

21 MR. BRATHIWAITE: I think the answer is,
22 yes, Commissioners. The natural gas market have
23 been in backwardation for quite a while. There
24 are very few times that I can recall that a market
25 was (indiscernible). Backwardation tended to be

1 the trend of things quite frankly.

2 PRESIDING MEMBER GEESMAN: I don't know
3 how safe it is to make a generalization out beyond
4 the most liquid point in a futures market. When
5 you say the futures market is anticipating prices
6 rise less than inflation, I guess the comparison
7 point that I would make would be with the treasury
8 yield curve out to that same time horizon.

9 You look at the two or three year time
10 horizon, and my hunch is, I've not checked this,
11 but my hunch is if you go back over the course of
12 the last couple of years, you are going to
13 consistently find that the futures price for
14 natural gas slope is substantially greater than
15 the treasury yield slope over that period of time.
16 I may be wrong. I certainly agree with you, you
17 can extend it out to a five year horizon, and you
18 are going to get a different result.

19 MR. HUNTINGTON: I purposely tried to
20 stay away from shorter term things because --
21 maybe I should emphasize this again, I really view
22 these models as providing a window on the longer
23 term issues.

24 PRESIDING MEMBER GEESMAN: That is a
25 good point.

1 MR. HUNTINGTON: That is why -- shorter
2 term, I think you have to start thinking about
3 other types of techniques and tools that will
4 compliment this analysis. That is a really
5 important point.

6 I guess this might be my last point,
7 which again, we had a great discussion just a
8 little while ago about gas and oil prices. I do
9 not believe they equilibrate on a BTU basis, but I
10 do think they are related.

11 Sometimes people say they are just not
12 at all related to each other and why should we
13 even think about it. I think that is not right.
14 I think that they do tend to move with each other.
15 When gas tends to be in surplus capacity, you tend
16 to have a lot of -- you often have what they call
17 "gas on gas competition". When it gets a little
18 tighter, it starts competing up against other
19 fuels like the oil price, and it might compete
20 with residual oil price. If things got really
21 tight, it would start competing distillate fuel
22 price which we are starting to see more of.

23 That is the question, where along that
24 chain does it start to compete. One of the things
25 that I think a supply demand analysis gives you

1 that has sensitivity both on the supply and the
2 demand side, where do these prices start fighting
3 each other. That will, of course, depend upon what
4 you assume about overall demand. It will depend
5 on what you assume about the cost of resources and
6 so forth.

7 I guess just to kind of close up here --

8 MR. MAUL: Hill, if I could go back to
9 that chart there, that point there. Do you think
10 that natural gas prices if for some time in the
11 history, natural gas has been cheaper than oil on
12 a BTU basis, do you think it will be more
13 expensive because it is a cleaner fuel, and there
14 will be a premium over it, or do you think because
15 of supply issues, it will still be discounted, or
16 does it matter, or do you jump back and forth?

17 MR. HUNTINGTON: I think gas will be
18 competing against higher quality oils and higher
19 quality fuels than it has in the past. This is
20 because of the supply issues that was well brought
21 out by the National Petroleum Council, but it is a
22 supply issue and partially driven by environmental
23 regions as well. I think the supply issue is
24 really kind of in mind swing it quite that way.
25 It is a more limited supply, therefore, it has to

1 be higher up on the value chain.

2 MS. KHOSROWJAH: I just want to ask a
3 question too. You indicate here that demand is
4 more elastic because of the prices when they go
5 higher and higher, but your assumption was the
6 change in technology would make the demand to be
7 more elastic. Could you summarize what are the
8 reasons behind an elastic demand because as you
9 know, it makes a huge difference when the demand
10 is elastic. I want to know, do you consider
11 energy efficiency, do you consider -- of course
12 when the prices go higher and higher, the
13 consumers cut into whatever they use. What are
14 the reasons behind elasticity of demand?

15 MR. HUNTINGTON: I'm primarily thinking
16 of I guess things that are induced by the higher
17 price of natural gas that bring on a piece of
18 equipment that previously wasn't cost effective or
19 there were other constraints on its penetration of
20 the market and all of the sudden people decide
21 they want to bring it on.

22 It could even be just an electric
23 generation thing. It could be a more efficient
24 generation plant that uses less natural gas to
25 generate power. That could be a price induced

1 investment that would happen that would reduce the
2 demand.

3 I am not talking about government
4 officials going out and saying independently a
5 price getting people to adopt energy efficiency
6 programs on their own because that is not being
7 induced by price. I am really trying to limit my
8 comments to those things that you would expect
9 would happen if the price of natural gas were to
10 remain high for an extended period of time.

11 Does that address the question that you
12 are -- I hope it does. No?

13 MS. KHOSROWJAH: It's okay.

14 MR. TOMASHEFSKY: One more question for
15 you actually. I look at this top ten list as if
16 you have a model tool that applies these things,
17 and you've got a utility approach modeling and you
18 are good to go. I guess it is really focused
19 really on the first five. How do you look at a
20 current model or a current NARG model and how it
21 fits into that spectrum under the assumption that
22 probably some of the demand related issues we will
23 probably talk about when Ken comes up here?

24 MR. HUNTINGTON: Right. I think it
25 picks up No. 2 very well. That is the approach,

1 and I think they made the right decision of
2 picking up this economic opportunity rather than
3 focusing on the old world where engineering
4 constraints determined cost and stuff. So, I
5 think that is where I would put the NARG thing.

6 MR. TOMASHEFSKY: There is some
7 interrelationship --

8 MR. HUNTINGTON: Definitely.

9 MR. TOMASHEFSKY: -- there.

10 MR. HUNTINGTON: Sometimes people will
11 argue that well, they are not picking up all the
12 engineering constraints, but it depends on how
13 well they characterize the -- there is the input
14 assumption, for example, it depends on how well
15 they are characterizing the resource cost curves
16 and does it have all the engineering constraints
17 in it, and does it have all the engineering
18 constraints on the pipeline. That I can't address
19 without going into further detail.

20 As I mentioned before, I think the older
21 system did not have prices effecting natural gas
22 demand, but what I understand this morning's
23 discussion was that they are bringing that level
24 in.

25 Industrial structure, I think you have

1 to do that off line almost. That is a very hard
2 thing. Most models don't really put this into the
3 model. They have to do kind of a lot of
4 assessment off line to pick that up.

5 MR. TOMASHEFSKY: I know your focus was
6 not on short-term modeling, but do you have any
7 comment in terms of how you deal with a long-term
8 construction and applying some short-term methods
9 to that to provide the continuous spot from today
10 and out twenty years?

11 MR. HUNTINGTON: This is an enormously
12 important issue, and it comes up all the time.
13 I've done a lot with people working on models of
14 the economy, macro-economic models. They have the
15 same kind of problem. They have one view of the
16 world and what the long term looks like and
17 another view of what the short-term looks like.

18 To some extent, I know people don't like
19 this response, but to some extent, I think you
20 have to take a different approach and evaluate it.
21 Particularly, you can use kind of statistical
22 analysis to look at short-term inventories and
23 prices. That is certainly one approach to try to
24 pick that up.

25 I don't think you can really take this

1 model which was really developed for I view for
2 more longer term issues and really represent 100
3 percent to your satisfaction that you have really
4 picked up the short run answers.

5 I often tell people there is a phrase
6 out there, it says, different horses for different
7 courses, and it is the race track analogy. I
8 think it is very true here. You've got to say
9 this model is good for this and now I need for
10 this kind of issue I need another. Then you have
11 got to in your own mind, you have to be able to
12 talk about the interrelationship between these
13 frameworks.

14 MR. TOMASHEFSKY: Absolutely. I know in
15 past years, we have always said we will pay no
16 attention to the front end of the long-term model,
17 and so, it just makes it problematic.

18 MR. HUNTINGTON: It does, it does. I
19 wish I had an easy answer for you, but I don't.

20 MR. GOPAL: Actually, let me take
21 Scott's question a little forward. What we have
22 done at the Commission realizing that we have this
23 permanent problem in a long-term forecast was to
24 look at the futures for the initial years, and
25 then merge it into the long-term fundamental

1 projection that we have from the model. Any
2 comments on that method?

3 MR. HUNTINGTON: That sounds like a very
4 reasonable approach. I can't see anything really
5 wrong with it. You might get arguments by some
6 people and say well, how good are these futures
7 prices and so forth, but in a sense, the future
8 prices is in a way sort of a structure piece of
9 information about what the short-term looks like.
10 I find that perfectly acceptable. You might be
11 able to put that in with some statistical models
12 as well. I think that sounds like a good
13 resolution actually.

14 Any other questions on that?

15 PRESIDING MEMBER GEESMAN: Thank you
16 very much. That was very helpful.

17 MR. HUNTINGTON: Thank you.

18 MR. MAUL: Our next presenter is Ken
19 Medlock, who is with Rick University, I think it
20 is the James Baker Energy Institute, did I get
21 that right, Ken?

22 MR. MEDLOCK: (Inaudible).

23 MR. MAUL: Ken has out here talking to
24 us about the demand elasticity issues. We are
25 trying to learn from him. Ken also worked very

1 closely with National Petroleum Council folks, and
2 they did their demand analysis, and so he has some
3 insight to that as well, and we have learned from
4 him on those issues.

5 MR. MEDLOCK: Thank you for having me
6 here, and I was asked to speak primarily on
7 implementing the elastic demand into the version
8 of NARG that the CEC uses, but I will note that I
9 can address a whole array of other questions if
10 you have them because in fact, I am quite
11 experienced with the software platform they are
12 using NARG in. In fact, at the James Baker
13 Institute for Public Policy, we are using the Alto
14 Software to develop a world natural gas model.

15 While all the data inputs into a North
16 American model are indeed tedious to keep up with
17 and kind of imagine if you extend that to a global
18 scale what it comes up to, so if you have any
19 questions about anything else, including some of
20 the questions that you asked Hill -- by the way, I
21 think he did a very good job about bringing up
22 some points with regard to elastic and then that I
23 will repeat. Please feel free to ask them.

24 First of all, what are we trying to
25 capture. I put in here a little note, and I put

1 this note at the top basically because a lot of
2 people avoid using elastic demands, and I don't
3 really understand why. The only thing that I can
4 come up with is that some times the statistics can
5 be a little daunting because what you need to do
6 is come up with a valid model that explains
7 reasonably well within samples so the data that
8 you have, but then you need to be able to make
9 sure that model also explains reasonably well out
10 of sample.

11 Sometimes this process is very time
12 consuming and a little bit frustrating at times,
13 but the benefits are enormous. Once you get down
14 to something that works, the benefits are very
15 nice. I'm going to try to elicit those here as we
16 go through this presentation.

17 What are we trying to capture with
18 elastic demand? I've drawn here just a very
19 simple representation of the demand curve that is
20 downward sloping in the price quantity space.

21 An inelastic demand curve would be a
22 vertical line. So, there would be no price
23 sensitivity, whatever you assume demand to be,
24 that is what it is regardless of price.

25 This can lead to some pretty erroneous

1 projections in particular as you move farther down
2 the road with a long-term model because if price
3 rises, which we would expect it to if you had an
4 upward sloping supply curve as demand increases,
5 you would actually see an offsetting impact of
6 reduction and demand due to price increases.

7 There is a lot of things that shift a
8 curve. The elastic demand version of the elastic
9 demands that are going to be implemented in the
10 NARG version of the model that CEC uses
11 incorporate all of these things.

12 We can shift the curve out by increasing
13 economic growth, increasing population growth. We
14 can increase the price of substitutes, and we can
15 decrease efficiency.

16 We can also have an effect of decreasing
17 demand, shifting the curve in along the quantity
18 axis by economic contraction, decrease in the
19 price of substitutes, and an increase in
20 efficiency.

21 Some of these things are the things that
22 Hill mentioned already. So, why use a model with
23 elastic demand? A lot of long-term models are
24 used to guide policy, and by no means are they
25 meant to, and I would be surprised who ever said

1 that they should be used as the end all be all for
2 policy. Rather, what a model should be used for
3 is a data point. A data point that is helped to
4 use to guide policy.

5 Obviously, there are experiences that
6 all of us have that can be overlaid onto the model
7 output, and sometimes they override model output.
8 Sometimes that is justified, but elastic demands
9 will help us to get a better picture of what
10 future demand will look like than say using an
11 inelastic demand node.

12 If supply comes at increasing costs --
13 let's go right through the slide here, as I
14 mentioned before demand that does not respond to
15 price will be overstated.

16 This can lead to a couple of things,
17 premature identification of resource depletion.
18 If you are not allowing demand to respond to price
19 and it is growing and growing and growing, it is
20 eating into your resource base faster than it
21 actually will. You will also have misplaced
22 emphasis on infrastructure constraints and
23 ultimately prices that are too high.

24 Each of these lead, as I have indicated
25 here, policy responses that are misplaced or

1 premature, and this imposes unnecessary costs.

2 We can have undue emphasis on efficiency
3 improvements in end-use, and inefficient
4 allocation of limited funds to policies that
5 ultimately have little impact.

6 We can also have inappropriate subsidies
7 to develop infrastructures.

8 One sort of issue, and I am by no means
9 taking a stand on it in this forum, is the Alaska
10 pipeline. There are entities in the corporate
11 sector that would argue for a subsidy for the
12 Alaska pipeline, but there are also entities on
13 the other side of the fence that say no, there
14 should be no subsidy, let the market bear what it
15 will bear.

16 Models can help us to identify whether
17 or not those sorts of issues should actually be
18 addressed in a public policy forum.

19 Here is an example. What I have done is
20 sort of started at the same place. What we have
21 is an upward sloping supply curve, we have
22 inelastic demands, those are the red and the pink
23 curves. The blue curves give us the elastic
24 demands.

25 We start at the same point, basically at

1 the same point of the supply curve, so we have an
2 initial demand assumption. If we use an elastic
3 demand formulation, we allow economic growth and
4 population growth and whether to influence demand
5 over time, we can either move to the red curve.
6 From the red curve to the pink curve, or from the
7 dark blue curve to the light blue curve.

8 If we use the elastic demand
9 formulation, we will have a very different outcome
10 with regard to price and the quantity of resource
11 that we are actually required to use.

12 You can see there that I have sort of
13 elicited what goes there. If we begin there at
14 the same equilibrium with the same supply curve
15 and low for demand growth, the price forecast is
16 too high if demand is inelastic. That is because
17 demand is overstated.

18 What the elastic demand allows you to do
19 is to say this is the impact of price over time.
20 This is the impact of digging dipper, drilling
21 deeper, getting more heavily into the resource
22 based. That is a finite resource base in North
23 American or globally either.

24 Notice here that the elastic demand and
25 inelastic demand projections would be identical

1 only if we had a perfectly elastic supply curve.

2 So, if supply is flat. That is definitely not the
3 case.

4 Other issue we can pick up if we use an
5 appropriate model specification, and that is the
6 differentiation between the long and short run
7 demands and the responses to prices. Typically in
8 the short run, we see or we observe that demand is
9 much less elastic. So, in the short run, there
10 are capital constraints, there are consumer
11 habits, there are things of this nature that sort
12 of override short-term fluctuations in price. You
13 don't see the responsiveness in the near term that
14 you do in the long term.

15 The long-term responsiveness will be
16 driven largely by capital turn-over, capital stock
17 turnovers, so we may, for example, perfect
18 example, actually, is what happened in the 1970's
19 to the 1980's with the automotive industry.

20 When the oil price impacts of '74 and
21 '79/'80 hit, the average fuel efficiency of a
22 motor vehicle on the road was about 12 miles per
23 gallon. By the time we reached 1991, the average
24 fuel efficiency of a vehicle on the road was 21.2
25 miles per gallon. We had increased the number of

1 miles we drive, we had increased the number of
2 vehicles on the road, but gasoline consumption
3 from about '81 to '91 was flat.

4 That is the impact of efficiency, and
5 those efficiency improvements were largely driven
6 by a policy response to price, both on the part of
7 government and consumers.

8 PRESIDING MEMBER GEESMAN: On the
9 consumer side, weren't gasoline prices declining
10 during the latter of the --

11 MR. MEDLOCK: Oh, they certainly were,
12 but that impact that you are talking about, that
13 is again, a long-term impact. You've exactly seen
14 from the early '90's to the present, a decrease in
15 the average fuel efficiency of the motor vehicle.

16 Because with declining gasoline prices,
17 you see a smaller and smaller impact per unit mile
18 driven on a consumer's budget. This is precisely
19 why these long and short-term impacts are
20 important, and they are important to distinguish.

21 What is elasticity? I'll sort of rip
22 through this real quick. Basically, the point is,
23 and it is a very important point that I want to
24 make here, we pause at some demand function, and
25 that demand function is basically going to tell us

1 that natural gas is a function of all kinds of
2 variables like income, population, if we are
3 talking about the industrial sector, maybe in
4 industrial production index. Weather, we have
5 heating degree, cooling degree measures. We have
6 technologies, we are talking about power. We
7 actually see that the rise in natural gas demand
8 through the '90's, for example, and power gen was
9 largely motivated by a decline in heat rate. So,
10 natural gas began to compete for base load power
11 demands.

12 We account for all of these things in an
13 appropriate demand specification, but then we want
14 to say well, what is the impact of price on
15 demand. Well, the appropriate way to do this is
16 to hold all other variables constant. That is
17 largely why when we pause at a function, we use
18 regression analysis to come up with elasticity
19 estimates.

20 I'm going to sort of go through all
21 this. If you don't do it right, you are going to
22 get the elasticities wrong. So, while I am
23 standing here saying you need to use elastic
24 demand instead of inelastic demand, you also need
25 to test a whole barrage of different models to

1 make sure that you've got it right, so you don't
2 have a problem of omitted variables that could
3 influence the outcome.

4 Again, I have here just a simple
5 example. I'll read through it here. Consider the
6 following example, if natural gas consumption has
7 been increasing at 2 percent a year for ten years,
8 income has been increasing at 3 percent a year for
9 the same time period, so when I say income, I
10 basically mean GDP, I naive approximation of
11 income elasticity of energy demand would be .67.

12 It is just the percentage change divided
13 by the percentage change. That is a very naive
14 approximation.

15 Now if we consider the price may have
16 been changing during the last ten years and our
17 naive estimate is incorrect, specifically if price
18 has been falling and given a downward sloping
19 demand curve, an income elasticity of .67 is an
20 overestimate and can lead to serious problems in
21 forecasting future demand. So, we need to be
22 careful that we pause at the correct demand
23 function. There are ways to statistically to test
24 which demand functions you may want to look at
25 that explain historical data best and explain out

1 of sample data best.

2 These are important issues because
3 inelastic demand will lead to its own problems as
4 I've said, misidentification of demand will lead
5 to erroneous elasticity estimates, and this can be
6 equally problematic.

7 What is the CEC implementing. I spent
8 some time yesterday with the natural gas group,
9 and we talked about developing the elastic portion
10 of their model. Basically, what we are using as a
11 benchmark is the work that was done in the
12 modeling sub-group of the National Petroleum
13 Council. The modeling sub-group of the National
14 Petroleum Council actually used the Alto Software,
15 so the market point software and developed its own
16 version of the North American Natural Gas grid.

17 It then layered in all of the same
18 estimates of supply of resource curves, the
19 diversion that are being implemented, the version
20 of NARG the CEC is using. We also developed our
21 own set of demand estimates. Those are the demand
22 estimates that we are working to implement into
23 the CEC version of NARG.

24 Here just briefly, these are what the
25 demand functions look like. Basically, it just

1 says residential and commercial by the way, I'll
2 just skip to the next one. Basically, are
3 functions of the same sets of variables. You have
4 an impact of GDP, an impact of price, and impact
5 of population, an impact of weather heating degree
6 days. I will note that were various
7 specifications tested here, cooling degree, I
8 asked to drop out of these two sectors because
9 their explanatory power statistically is not
10 significant.

11 There is a lag adjustment. The lag
12 adjustment is meant to capture things that I
13 mentioned before, and it helps to differentiate,
14 such as habit persistence and capital stock
15 turnovers, etc. etc. It helps us differentiate
16 between the long run and short run impact of the
17 change in price or a change in income or a change
18 in population or a change in weather, these kinds
19 of things.

20 Just a quick note, the largest driver in
21 the residential sector is population. That really
22 is not very surprising. All the elasticities have
23 the appropriate sign which is another comforting
24 thing.

25 You ever do regression analysis on a

1 model and you get the wrong sign, it tells you
2 there is something wrong with your model most
3 likely.

4 Then commercial demand, the largest
5 driver here is GDP.

6 Now on the industrial side, demand is
7 actually split into the chemical and all other
8 industrial demand sectors, so there was a lot of
9 work done by the industrial demand sub group at
10 the National Petroleum Council along with EEA,
11 which is a consulting firm to develop industrial
12 demand projections for the National Petroleum
13 Council model, and they got down to the SIC code
14 level to look at natural gas consumption by
15 individual type of industry.

16 What we then did in the modeling sub-
17 group is take those results and develop our own
18 estimates using the data that they provided to
19 come up with various elasticities. A note here
20 that in the industrial sector, both chemical and
21 non-chemical, industrial production is the "income
22 measure" that we use.

23 There is a known price effect, so
24 natural gas prices effect demand. There is a
25 cross price effect here, so oil prices or oil

1 product prices influence demand as well.

2 Then there is a lagged impact. Again,
3 that is largely due to capital stock turnover or
4 contract (indiscernible). For example, an
5 industrial consumer may not need to respond to an
6 immediate increase in price because they are
7 contracted up to the next three to six months at a
8 lower price. So, the response can be delayed
9 oftentimes.

10 Now with regard to power generation
11 demand, and this has already been touched on, the
12 gas market model is going to be iterated against
13 the structural model that resides here at CEC.

14 Why not do a statistical model? Well,
15 the biggest reason is that for the available which
16 is actually quite short because the EIA, which is
17 really the only data bank we have to go,
18 restructured the way they report data between
19 power generation and industrial demand, and the
20 data only goes back to 1997 now.

21 Now for power demand, that is extremely
22 problematic because it can be argued that the late
23 '90's were characteristic of what we call a
24 structural shift in the market place. For
25 example, if you have a technological change that

1 becomes implemented very rapidly during a five to
2 seven year window, as is the case for power
3 generation, you've got a lot of new build natural
4 gas combined cycle facilities which heat rates are
5 well below 8,000 as opposed to the old steam units
6 where you've got heat rates that are sometimes 30
7 percent higher than that, so they are much lower
8 efficiency.

9 You begin to see gas compete for base
10 load power generation. So, gas consumption rises
11 as a result of that because these units, although
12 they are more efficient, they operate longer hours
13 of the day.

14 So, in order to capture those kinds of
15 structural changes and not extrapolate them into
16 the future as would be the case if you tried to do
17 an economic estimation of just that limited data
18 sample. It is best and it is my recommendation
19 actually that they continue in the fashion they
20 have been going, and that is iterating between the
21 models.

22 Now one of the other things that came
23 out is the model really only focuses on the WECC,
24 and we know that the power model -- and the gas
25 model focuses on the entire North American grid.

1 One of the paths that we are going to
2 take is actually use the EIA scenarios from the
3 annual energy outlet for 2004 and try to marry
4 those to the different scenarios that are run for
5 the WECC so you will have consistent sets of
6 assumptions with regard to power generation demand
7 going forward. That's it.

8 PRESIDING MEMBER GEESMAN: How many
9 regions?

10 MR. MEDLOCK: How many regions --

11 PRESIDING MEMBER GEESMAN: In the
12 elasticity modeling that you did.

13 MR. MEDLOCK: I've had to roll up a lot
14 of the analysis for CEC, but I believe -- how many
15 demand regions are there total, maybe 17, 18,
16 something like that. There is a lot of
17 aggregation east of the Rockies with regard to
18 demand in infrastructure.

19 There is something like that, 17 or 18,
20 and then there are five different consuming
21 sectors as I just went through in each of those
22 regions.

23 PRESIDING MEMBER GEESMAN: If you've got
24 that much aggregation east of the Rockies, how are
25 you deriving your tech residential, for example,

1 how are you deriving your residential elasticity
2 for regions or state-wide number in California?

3 MR. MEDLOCK: It's statistical. You can
4 use available data from on heating degree
5 available from NOA, and those are actually
6 aggregated up to the census region level which is
7 quite nice because that is exactly how the demand
8 regions are aggregated by CEC east of the Rockies.
9 So, use those variables, you can use the price
10 data. Typically what I have done there is use a
11 consumption weighted average for prices by end use
12 sector because you may or may not know, EIA
13 reports data up to state level, and they have city
14 gate and end use prices as well as pipeline fuel
15 prices.

16 What you can do is go through and use
17 those prices when you are aggregating, weighted by
18 the total consumption in that state in that
19 particular census region to develop a volume
20 weighted average if you will of what the prices in
21 a particular census region.

22 The income measure is generic across all
23 states. It is just US GDP. We did actually play
24 with using gross state products, however, there is
25 a lot of noise in that particular method. A lot

1 of that has to do with there are virtually no
2 barriers to trade across state borders. So, you
3 can have industries that are located in one region
4 producing intermediate products that are then
5 converted into final products in a different
6 region. That won't necessarily be reflected in
7 the gross state product numbers.

8 The population data is obtained from the
9 Census Bureau. The other problem with the gross
10 state product is you've got to forecast it. So,
11 GDP is something, a forecast are readily available
12 to third parties such as the Bureau of Economic
13 Analysis, so, that is another advantage of using
14 that going forward.

15 Population numbers are also available.
16 Forecasts are available from the Census Bureau,
17 and those are actually used in developing the
18 forecast for demand.

19 PRESIDING MEMBER GEESMAN: One of your
20 slides indicated the risks involved with
21 overstating demand. I presume that you would also
22 be available to identify risks of understating --

23 MR. MEDLOCK: Oh, absolutely.

24 PRESIDING MEMBER GEESMAN: -- demand.
25 Are they symmetrical risks or --

1 MR. MEDLOCK: It depends on the point of
2 view of the person viewing the risk I would argue.
3 A near term risk can be very detrimental. For
4 example, if we actually understate demand and
5 don't identify an infrastructure constraint that
6 develops, it can be very detrimental to a lot of
7 people in the very near term. Corporate CEO's,
8 policy makers, etc. etc., the list goes on.

9 Longer term risks are primarily the
10 burden born by those risks is primarily on the
11 consumer to the general public. So, as I said, it
12 depends on the individual that is looking at the
13 risk or assessing the risk.

14 PRESIDING MEMBER GEESMAN: Thank you.

15 MR. TOMASHEFSKY: I just have one
16 question for you, Ken, before you go. Is there
17 any basis for the variables you have chosen? Is
18 there a larger list that you just didn't look at
19 in time or --

20 MR. MEDLOCK: Yeah, that is a good
21 question. What you typically do when you go
22 through this process is you -- one of the first
23 ways to go about it is check the literature, the
24 academic literature. People have actually looked
25 at this and spent a lot of time looking at these

1 kinds of issues.

2 Then you need to come up with some sort
3 of sound theoretical basis for including certain
4 variables and a demand function. You know, that
5 is a much longer conversation, but suffice it to
6 say that once you have done all of this, you come
7 up with multiple functional forms that you would
8 like to test on the data. The data will tell you
9 which functional form is doing the best job of
10 explaining it in this regression setting. You do
11 that, that is not the end all be all because you
12 would also like the data to tell you a little bit
13 about out of sample properties, and it does happen
14 sometimes that the model that explains the data
15 best in sample does not do the best out of sample,
16 so you need to weight those things, you need to
17 balance those things. There is a trade off
18 involved.

19 MR. TOMASHEFSKY: This is to suggest
20 this is your best estimate. If you were to add
21 anything else, I guess, the question is it would
22 be considered statistically insignificant --

23 MR. MEDLOCK: That's right. In fact,
24 what we do, we started with a larger set of
25 variables and dropped the one that were

1 statistically insignificant.

2 MR. MAUL: Before he leaves, anybody in
3 the audience have any questions at all?

4 UNIDENTIFIED SPEAKER: I didn't have all
5 the handouts of those coefficients that you were
6 using there, but could you explain why the
7 coefficients were so low for the other industrial
8 sector? Is there a relationship to GDP growth? I
9 see like .0919 and .0368. What does it mean
10 regarding other industrial demand, what is it most
11 closely related to and how elastic is it?

12 MR. MAUL: Ken, can you summarize the
13 question for the audience?

14 MR. MEDLOCK: Yeah, the question is
15 basically regarding the elasticity estimates for
16 the industrial demand, non-chemical industrial
17 demand and why are the elasticity estimates
18 apparently so low.

19 Basically, what the data reveal is that
20 there is a tremendous amount of sluggishness in
21 the system regarding industrial demand, non-
22 chemical industrial demand. So, things such as
23 capital stock turnovers or potentially other
24 policy drivers are really what is driving what
25 happens. That is why when you look at the lag

1 coefficient, it is highly significant. In
2 standard errors, .007, and the estimate is about
3 .45. That is what did the most or what had most
4 of the explanatory power, and that actually argues
5 that it is probably best described as a
6 distributed lag type of demand function. However,
7 we are limited in some sense in what we can
8 implement in the Alto software because it only
9 allows for a single lag of approximation. So,
10 that is why we went with this.

11 You will note that the cross price
12 elasticity or what I have called the oil price
13 elasticity is actually -- actually, I've got this
14 written wrong. This thing should be -- that
15 should be positive. That is okay. It is the
16 magnitude on the things. The price elasticity is
17 actually .09, and the cross price is .02, I've got
18 those two, but the signs are correct there, but
19 they are incorrect in the presentation.

20 The point there is the cross price
21 elasticity in the non-chemical industrial sector
22 is actually not statistically significant, but it
23 is left in the analysis because by and large at
24 the NPC, there was a lot of focus on developing
25 these cross price relationships, so we wanted it

1 to influence the forecast nevertheless.

2 UNIDENTIFIED SPEAKER: Does this say
3 that if the GDP growth, if you were to change the
4 GDP growth in a region of the country that would
5 affect industrial demand?

6 MR. MEDLOCK: A lot of what is coming
7 out here is something that Hill actually alluded
8 to earlier, and it is the shift in not just
9 industrial structure, but economic structure.

10 In the US, from the 1950's to the
11 present, we have gone from a society that was
12 roughly 40 percent industrial based to a society
13 that is roughly about 22 percent industrial base.
14 So, of our total output, only about 22 percent of
15 it comes from the industrial sector.

16 We are a largely a service based economy
17 now. We are up over 70 percent total output is
18 explained by service oriented enterprise. What
19 you are seeing here with regard to the IP
20 elasticity, that is the defective industrial
21 production changes on natural gas demand is partly
22 due to that because the industrial structure has
23 shifted away from heavier industries to lighter
24 industries, which are less energy intensive just
25 generally.

1 MR. TOMASHEFSKY: One other question, I
2 guess this is the question of elasticity of the
3 elasticity, when would you see a need to revisit
4 these coefficients?

5 MR. MEDLOCK: They should be in every
6 time new data is released. So, on an annual basis
7 basically because one of the problems of doing
8 statistical analysis is that data is revised. So,
9 each and every time data is released, you need to
10 revisit the issue.

11 MR. MAUL: Any more questions for Ken?
12 Okay, Ken, thank you very much for your
13 presentation today.

14 Next up we have Luis Pando from Southern
15 California Edison who is going to talk about their
16 view of modeling. Luis, thank you very much for
17 coming up here. Just a logistical note for folks
18 that are on the conference call, the website and
19 the power point presentations are available on the
20 website.

21 It may not be obvious how you get to
22 them, but if you go to the Energy Commission's
23 main web page, go to IEPR, go to the notice for
24 today's, December 16 hearing, there is a link to
25 all the presentations that we have so far. There

1 are a few presentations that we have not yet
2 physically gotten that are being presented today
3 that we will load as we get them later today.

4 Luis, thank you very much.

5 MR. PANDO: First of all, I would like
6 the Commission for this opportunity to address
7 this workshop. I think it is addressing a very
8 important topic and definitely impacts Southern
9 California Edison and the price of power we see
10 for our ratepayers.

11 I'm going to concentrate my discussion
12 on the impact on the electric generation market.
13 The ability to forecast the California gas market
14 requires a competitive and open market structure.

15 All of these models assume that there is
16 non-discriminatory access to supply and
17 transportation.

18 Gas is a dominant resource for setting
19 power prices in California. In California, the
20 greatest share of our electric demand is met by
21 gas fire generation and in most parts of the
22 country. In addition to that, it is the dominant
23 marginal fuel in California. Any modeling process
24 should include the impact of electric generation.

25 In addition to that, gas is becoming an

1 increasingly national market, and with the impact
2 of LNG, it will become an international market if
3 that is the option the United States sees for
4 meeting gas demand. I think, therefore, any
5 modeling approach needs to consider these impacts.

6 In addition to that short, mid, and
7 long-term effects need to be considered. I think
8 traditionally in process such as the California
9 Gas Report, long-term effects tend to be
10 considered. As the crisis in California showed, a
11 lot of damage can be done in very short-term and
12 short-term impacts need to be examined. I commend
13 the Commission for beginning to look at shorter
14 term impacts also.

15 First of all, I am going to talk about
16 some policy issues that Edison feels is necessary
17 to have a properly functioning market. We do
18 think they should be equal to transportation
19 services by all customer classes.

20 In addition to that, information should
21 be provided equally to all customer classes. Just
22 to be sure, what Edison is not advocating is
23 revealing confidential information that would
24 reveal the market position of any party. We are
25 not asking that commodity position or anything to

1 reveal but the amount of transfer capability that
2 is available needs to be equally -- the
3 information needs to be equally distributed.

4 PRESIDING MEMBER GEESMAN: Now by
5 raising that, do you believe that there is not
6 presently equal access to transportation services
7 or to information on transfer capacity available
8 to all customer classes?

9 MR. PANDO: I think that some of the
10 current -- I think SoCal Gas filing for firm
11 access rights is a step in the right direction.
12 It is a little murky exactly the transfer
13 capability between the border and to the burner
14 tip currently. I think that is a step in the
15 right process.

16 I just want to stress that is important
17 to a properly functioning market.

18 PRESIDING MEMBER GEESMAN: You feel that
19 presently, as it relates to the electric
20 generation sector, there is still improvements
21 needed to be made.

22 MR. PANDO: Yes, and again, we think the
23 firm access right is a step in the right
24 direction. We feel that proceeding will help. I
25 think PG & E's system is much more (indiscernible)

1 in that sense, and we think SoCal Gas filing is a
2 step in the right direction and we will be an
3 active participant in that filing.

4 In that mode, you know, the separation
5 between transportation and commodity functions
6 still are a concern. Procurement for the core is
7 a dominant procurement function in California.
8 They tend to be the dominant buyers at the
9 California border. The thing to remember is that
10 if you disadvantage the non-core customers, most
11 of these customers are also electric customers.
12 Any driving up of gas prices to electric
13 generation is going to be reflected in the
14 electricity bills. So, those incentives need to
15 be carefully considered.

16 As it has been talked about a lot,
17 electric generation is the driving increase,
18 driver increase demand for natural gas in the
19 United States. It is projected to grow by the EIA
20 from 23 percent in 2005 to 30 percent in 2025.

21 California has already a large section
22 of its electric generation met by natural gas.
23 The biggest growth is coming in the east coast,
24 and I have heard people talk about how do you --
25 you know, talking about the WECC only on the

1 electric side. You really need to think about the
2 electric demand on the East Coast and more and
3 more in the midwest, because that is becoming more
4 and more gas fired dependent.

5 Unfortunately, this leads to a lot of
6 complication and may not be totally doable, but it
7 is a big concern.

8 What are the fundamentals behind --
9 well, fundamentals are the drivers to electric
10 generation gas demand. Weather, for instance, in
11 the winter of 2000 - 2003, we had a relatively
12 mild winter in California, but there was extremely
13 cold weather event in the northeast. That not
14 only drove gas demand for residential heating also
15 drove gas demand for electric heating. Therefore,
16 we saw a big rise in prices on the California
17 border. So, it is a national market.

18 Production for non-gas fire generations
19 will also affect demand. The nuclear fleet is
20 aging in the United States, and whether to renew
21 that nuclear fleet is going to be a big question,
22 a big driver of gas demand.

23 In addition to that, coal is also an
24 aging fleet in the United States, and
25 environmental policies will affect the amount of

1 power being generated by coal power. That should
2 also be considered.

3 Another problem we face especially in
4 the west is a year to year variability in hydro
5 electricity in the west. We do not have multi-
6 year storage for most of the hydro in the west,
7 and we are very dependent on each annual snow
8 pack. That makes volatility on a year to year
9 basis probably a bigger driver in the west than in
10 other parts of the country.

11 One other thing is the instantaneous
12 nature of the electric market requires I think
13 very detailed daily or short-term analysis and its
14 specific transfer point analysis. One thing, a
15 trend that has been going on in the future is more
16 and more electric generators are connecting to
17 interstate pipelines that tend to have limited
18 balancing capability.

19 The incremental units tend to be
20 connected to the LCD companies, and that needs to
21 be looked at to make sure there is enough
22 infrastructure to meet variability and demand.

23 MS. KHOSROWJAH: Could you elaborate on
24 that point?

25 MR. PANDO: Most of the combined cycles

1 have been connecting to the interstate because
2 they see a lower price for their transportation.
3 Most of these combined cycles were envisioned to
4 run at very high base load capacity factors. That
5 is the reason they chose interstate pipelines.

6 With the over building the market, the
7 capacity factors on these combined cycles have
8 been a lot less than expected. Therefore, they
9 are tending to have to swing or low follow more
10 than expected.

11 Interstate pipelines tend to have much
12 tighter balancing rules than the LCD's that have
13 storage fields and can provide greater balancing.
14 This needs to be looked at to make sure that it
15 can meet the instantaneous changes in electric
16 demand.

17 MR. TOMASHEFSKY: Let me ask a question.
18 This kind of refers back to Ken's discussion just
19 before. Weather related elasticity we deal with
20 heating degree days, so to the extent that hydro
21 production in the west is important, how do we
22 account for that in terms of demand elasticity, or
23 how can we account for that because the way it is
24 set up right now, it has no impact based on what
25 is here, and yet we have shown historically that

1 it makes a big difference in the west.

2 MR. PANDO: I think the Commission and
3 what I heard today is on the right track about
4 producing shorter term forecasts. Maybe a gas
5 forecast. The snow pack is pretty much known by
6 the time the spring rolls around. Maybe a gas
7 forecast at that time to talk about the
8 variability.

9 MR. TOMASHEFSKY: Suppose you come up
10 with a global warming type of scenario where you
11 are now assuming your hydro-production is 20
12 percent less than what it normally is? We don't
13 account for it here in terms of what we can do
14 model wise, at least to what Ken described.

15 MR. PANDO: One of Ken's variables will
16 be weather.

17 MR. TOMASHEFSKY: Heating degree days.

18 MR. PANDO: Heating degree days, yes.

19 MR. TOMASHEFSKY: Is that flexible
20 enough --

21 MR. DI GIOVANNA: Actually, Scott, for
22 what hydro is going to matter for in our model
23 will only be electricity generation. Since the
24 way we are going to handle electricity generation
25 actually won't be through the demand functions

1 that Ken was talking about, it will actually be
2 done by iterating for at least for the WECC by
3 iterating with the Electricity Office, so when
4 they come up with their hydro forecasts and how
5 they incorporate that into their forecast and what
6 resources they will use, that will then influence
7 our gas forecast for electricity generations.

8 MR. TOMASHEFSKY: That makes sense. So,
9 we just need to make sure if we run sensitivities
10 related to that, we have to --

11 MR. DI GIOVANNA: Right, right. That
12 is --

13 COMMISSIONER BOYD: The question is
14 relevant.

15 PRESIDING MEMBER GEESMAN: That hydro
16 topic will be the subject of another day or
17 several days.

18 COMMISSIONER BOYD: Before you leave
19 this page, your bullet about production from non-
20 gas fired generation resources, your point about
21 aging fleets in nuclear and coal were certainly
22 correct. I am just wondering if you are willing
23 to venture any point of view of your company about
24 this subject such as say nuclear.

25 What I am seeing for better or for worse

1 and just observing is that most nuclear plants are
2 getting relicensed after the electricity crisis
3 versus an opinion that an attitude before the
4 electricity crisis that they would likely phase
5 out. Of course, one of the dreams of deregulation
6 in California was an early phase out. That bubble
7 burst real quick. With regard to coal, you said
8 coal environmental regulations can effect the
9 availability of electricity from coal, but what I
10 am debating in my mind is does it affect price or
11 availability more. Of course, they are
12 interactive, but environmental regulations may
13 raise the price of coal, but with the huge
14 interest in coal and the great concern, you know,
15 you can make electricity from coal very clean. It
16 just costs more to do so.

17 How do you view things like that? We've
18 already done the hydro and California's path on
19 renewables is pretty clear.

20 MR. PANDO: I'll be speaking more from a
21 personal level and not representing Edison, I do
22 feel that the United States is the largest holder
23 of coal reserves in the world. I think it is an
24 important fossil resource for the United States.
25 It not only reduces our dependence on foreign

1 sources for fossil fuels, but in addition to that
2 if it can be cleaned, I think it would be an
3 important mix in the electric market.

4 I think the carbon is a big problem with
5 technologies such as coal gasification still, and
6 I think carbon (indiscernible) technology needs to
7 come up to speed to capitalize on the fuel.

8 In addition to that, on the existing
9 coal fleets, potential mercury limitations could
10 really reduce the amount of production. At the
11 moment, the only option we really have is natural
12 gas, so that would stress a natural gas system.
13 If these kind of environmental constraints reduce
14 production from coal power.

15 Edison feels that natural gas is a
16 national market and growing into an international
17 market. The growing interstate pipeline system is
18 allowing supplies from all the bases to meet
19 demand in all parts of the United States.

20 One of the new pipelines that is going
21 to be drawing gas from the Rockies eastward will
22 impact the price that we see on the border in
23 California.

24 It is important and I think the Energy
25 Commission is on the right modeling path to look

1 at these nationwide impacts on California border
2 prices and supplies.

3 One thing that we wanted to stress is
4 LNG supply, whether imported in the Gulf Coast or
5 any other part of the United States will help the
6 supply in California by redirecting domestic
7 supplies to California. So, it is important to
8 not favor one option versus another. It is
9 important to let the market decide as much as
10 possible. Subsidies should be carefully considered
11 before making them.

12 The other problem is the reliance on LNG
13 will require us to consider an international
14 market place. Asia is a big competitor for liquid
15 natural gas and becoming more and more so.

16 We will face international competition
17 if LNG is the option we choose to meet our growing
18 gas demand.

19 I talked about short term and long term.
20 I am going to try and identify what we see as some
21 of these effects and why they should be
22 considered.

23 On the short term, weather temperatures
24 and spikes in weather temperature can effect
25 electric gas demand. Power plant outages such as

1 nuclear power plant really determine our need for
2 withdraw and injection capability of our storage
3 fields. That is an important thing to think about
4 as again, more and more generators are sited off
5 interstate pipelines.

6 In addition to that infrastructure
7 outages, we need to consider what would be the
8 impact of an instantaneous outage on a pipeline to
9 the gas system in California.

10 For mid-term effects, again, the biggest
11 one is the snow pack. The varying snow pack does
12 cause a quite a volatility in annual gas prices
13 and will impact gas demand, not only in
14 California, but in the United States.

15 In addition to that, we need to
16 carefully track the nuclear refueling stations
17 because another problem in the crisis was the
18 multiple nuclear refills we had that winter in
19 addition to a snow pack year, and I think the
20 scenario approach is that they take in their
21 modeling will take a look at those and the system
22 and the stress of the system in those times should
23 be looked at to examine whether there could be
24 price manipulation.

25 Long-term supply changes -- there is

1 more time to react to long-term issues, but access
2 to new basins, such as Alaska and LNG will have to
3 be considered in prices going forward.

4 Changes in gas infrastructure such as
5 pipelines and storage will determine where
6 generators are sited. Peaking plants tend to be
7 connected off LCD's at the moment because peaking
8 plants have to provide balancing services
9 essentially on the electric system.

10 Interstate pipelines are considered
11 storage projects and you may see more of these
12 peaking resources located off the interstate so
13 they can provide balancing services.

14 Lastly, as far as power generation
15 options, and again, these have been iterated
16 before, non-gas versus gas is going to be the key
17 issue going forward for future gas demand.

18 The success of coal gasification will
19 impact largely the future gas demand in the United
20 States and there is a lot of interest and growing
21 interest in this technology and the potential is
22 great there.

23 I think the announcement by General
24 Electric to partner with Bechtel and offer
25 commercial gasification plants states to me that

1 the technology is getting very serious and near
2 commercial opportunities.

3 In addition to that, coal gasification
4 does solve a lot of the environmental problems
5 associated with coal and theoretically could
6 potentially even be sited in California.

7 The last issues, again, the retirement
8 of the aging low base fleet needs to be looked at,
9 coal, nuclear power plants. These will impact gas
10 demand greatly and should be looked at in the
11 long-term modeling.

12 That concludes my presentation.

13 PRESIDING MEMBER GEESMAN: Does Edison
14 do its own gas forecast?

15 MR. PANDO: We are beginning to upgrade
16 in that area. At the moment, we rely mostly on
17 vendors, but we do realize the importance of that
18 to Edison.

19 PRESIDING MEMBER GEESMAN: Do you
20 envision doing both a short-term and a long-term
21 forecast or is it too soon to tell?

22 MR. PANDO: We probably would. The
23 thing about short-term is market dominates. I
24 mean we may have a fundamental view of the market,
25 but the market is a market, so I think there will

1 always be a reliance on the market, though we may
2 do some modeling in that mode. Long term, since
3 we are back in the gas procurement business in a
4 big way, we need to look at interstate investment,
5 pipeline investment, LNG, and these kinds of
6 things will begin to be assessed internally.

7 MR. TOMASHEFSKY: You would have to
8 become a player again in California gas report,
9 the annual report, because I know you were before,
10 and then when we went away and you went away, so
11 now you are coming back?

12 MR. PANDO: Yeah, I think my presence
13 here talks to that exactly. We are a major player
14 already in the gas market. We are a large buyer
15 of natural gas today, and with Mountain View, our
16 power plant coming on line in 2006, we will just
17 increase our position.

18 MR. MAUL: Luis, you obviously are from
19 the electric company, and this is a gas modeling
20 workshop. We are talking about electric issues
21 that influence gas modeling and you do your own
22 electric modeling. You buy vendors on the gas
23 modeling. Do you have any thoughts on how we
24 integrate the gas and the electric modeling so
25 instead of having of two different ones that have

1 to talk to each other, do a better job
2 interviewing those?

3 MR. PANDO: I think that is a lofty
4 goal. It would be I think in the long-term that
5 is a much more achievable process because you can
6 begin to aggregate, like for instance resources in
7 the long-term. In the short-term, it is a much
8 more difficult process because you need detail in
9 the short-term. It is definitely a lofty goal,
10 and I think that it is something that Edison we
11 would attempt to do because they are integratedly
12 tied and there is no way to model one without the
13 other.

14 MR. MAUL: Any questions from the
15 audience? Yeah, Mark.

16 UNIDENTIFIED SPEAKER: What modeling is
17 Edison using for the long-term gas forecast?

18 MR. PANDO: At the moment, we are not
19 using any models, we are getting vendor supplied
20 prices at the moment. I think we are interested
21 in developing the expertise in-house and it is
22 something that we are exploring.

23 PRESIDING MEMBER GEESMAN: Thank you
24 very much. That was quite helpful.

25 MR. MAUL: Thank you, Luis.

1 Commissioners, I want to take just a quick
2 logistic check here. It is 11:40, we obviously
3 can't complete everything before lunch, so we need
4 to take a lunch break and come back from lunch.
5 We have several other presentations lined up to go
6 through. We have two folks who have come down
7 from Canada that have two different presentations,
8 Walter and John.

9 I do not know how long your joint
10 presentations are going to take whether we can get
11 them in before lunch. After you, if it takes
12 longer, we actually switch order and go to Katy
13 Elder, Katy can get her presentation in before
14 lunch.

15 I didn't know whether you want to take a
16 break right at 12:00 or before 12:00 or after
17 12:00 or when you had any constraints on coming
18 back before or after 1:00.

19 COMMISSIONER BOYD: Does anybody have
20 any transportation logistic problems that needs to
21 go earlier rather than later.

22 MR. MAUL: Seeing none. I guess we are
23 flexible, so it is your schedule for when we take
24 a lunch break and how long we take it for, so I
25 can get folks on the phone lines an indication of

1 what is going to happen.

2 PRESIDING MEMBER GEESMAN: Why don't we
3 stop at 12:00 and come back at 1:00.

4 MR. MAUL: Okay, we will plan on that.
5 So, Walter, John, do you want to -- can you guys
6 get in the next 20 minutes, or do you want to go
7 after lunch.

8 MR. DIMATTIA: It might be myself then
9 John.

10 MR. MAUL: Okay, sounds good. This is
11 Walter DiMattia from TransCanada Pipeline, and he
12 has been down to California before to talk to us
13 about their views on Canada issues. Walter, thank
14 you very much.

15 MR. DIMATTIA: First of all, I would
16 like to thank the Commission for having me come
17 and speak to you. By way of background, I just
18 want to explain a bit about my own background, so
19 you can get to know why I am speaking on this
20 topic.

21 My experience is pretty much all
22 upstream. I spent twelve years at BP, all in if I
23 could characterize my experience, it has been
24 upstream at BP, all gas pretty much, all Western
25 Canada. I worked in mostly in the exportation and

1 the reservoir engineering fields. I have done gas
2 operations.

3 I have worked in petrophysics, and I've
4 also done corporate economics. Then I went to
5 TransCanada, and I work in the supply forecasting
6 area.

7 The group that I work in is about eight
8 people, consists of about two geologists. I guess
9 you may wonder well, why this TransCanada, why is
10 TransCanada calculate supply costs, or why do we
11 have such I guess maybe like a large fairly big
12 supply team?

13 The answer is that why we calculate
14 supply costs is we need to do a supply forecast.
15 I guess that the thing TransCanada sits on a
16 fairly large basin, the second largest basin in
17 North American, and we not only have like a total
18 aggregate need, but also like a regional need to
19 understand the supply.

20 They are fairly long lived assets, so
21 when we make those investments they have to be
22 there for a long time.

23 We also, in terms of why we do a supply
24 forecast, there are strategic needs. We do an
25 annual Northern American supply demand outlook,

1 and why we do that is so we can determine the
2 flows on the various pipeline segments.

3 We also look at opportunities. On the
4 supply side, we mostly talk about supply
5 attachment opportunities.

6 On the competitive issues, we also have
7 the problem with bypasses, and so we need to
8 assess that. Also TransCanada sits down stream of
9 the Northern Gas, so we are looking at that.
10 Unconventional is becoming fairly big, and so we
11 are assisting that impact. That also impacts the
12 commercial basis.

13 We have quite a few customers, and we
14 want to better understand our customers in the
15 upstream industry.

16 The second need is regulatory. The
17 supply forecast is used in our depreciation
18 calculation which is part of the total
19 calculation.

20 In depreciation, you need to calculate
21 the economic life. The economic life can be based
22 on either a physical life, look at like a market
23 life or a supply life. Now the physical life of a
24 pipe is about 50 years, so that doesn't come into
25 play, but as far as the market is concerned, there

1 will always be demand for gas, so that doesn't
2 come in to play.

3 For TransCanada, it comes down to the
4 supply. It depends on how much supply there is
5 and when that gas is gone, then our pipeline will
6 not be used or useful.

7 The second need for the regulatory is
8 what we call the business risk. We are a regular
9 pipeline. We have allowed a profit. The business
10 risk is composed of a lot of different types of
11 risks. What I focus on is what is called the
12 supply risk.

13 So, there is a lot of work that is put
14 into that effort. In fact, right now there is a
15 hearing up in Canada on our main line we are going
16 through a fairly lengthy process on the business
17 risk portion of the hearing.

18 The last, there is operational needs.
19 So, we are always looking at facility solutions,
20 looping versus compression and those sorts of
21 things.

22 I guess what I will talk about is when
23 people talk about doing supply forecast, various
24 people, various agencies have certain things that
25 they can bring to a forecast. What does

1 TransCanada do?

2 We can buy data, but what makes our
3 forecast a bit different is that we have quite a
4 few customers. The last time I checked we had
5 1,918 customers and a lot of them are producers.
6 Quite a few of them signed long-term financial
7 type of contracts, so they are fairly committed.
8 That information tells us what they plan to do or
9 what their feelings are about the basic.

10 We also have a lot of customer
11 interactions. Because we don't compete with out
12 customers, they will talk to us, they will talk
13 about their plants that they probably would not
14 talk with anybody else. That also includes the
15 regulators.

16 The third point there, I guess, the same
17 things apply to the third point on the storage
18 operators. The thing that I have to say there is
19 that and there we are mostly looking at the
20 working gas levels, and now as we are getting more
21 and more into the storage business ourselves, we
22 are getting less and less cooperation with the
23 storage operators. So, probably the next time I
24 do this presentation, I'll probably take that
25 third bullet off.

1 I guess basically what is happens is
2 when we do supply forecasts, we think we have
3 another perspective that possibly others don't.

4 I'm not going to go through all the
5 slides here, but what I want to do here is just go
6 through the what is different about how we do
7 supply costs. This is a methodology forum, I want
8 to talk more about the how to rather than what the
9 actual forecasts are.

10 Now in Canada, we are able to look at
11 pool size distributions as opposed to field size.
12 Like in the US it is mostly on fields, and Canada
13 is mostly pools. The methodology is the same.

14 What I want to talk about is what is
15 different with us is that we spend a lot of time
16 looking at what we call economic truncation. We
17 would look at there is an undersampling of like
18 pools and so we try to account for that. I will
19 show some slides how that works.

20 The other thing, too, is that we look at
21 the discovery process, the finding rate analysis.
22 What that gives us is what we call a blended
23 supply cost curve. So, it is not perfect
24 foresight.

25 The last thing we do is we apply

1 technology factor.

2 On the pool size or field size, what you
3 want to look at is that on the large size, we have
4 what is called a peer review, so the experts go
5 look at the large size, and they will tell us what
6 they think are the largest undiscovered pools.

7 On the small size this is where economic
8 truncation comes in. There is a lot of
9 statistical work that goes into it. That
10 basically forms what I call the low and high
11 sensitivities for the potential.

12 Giving you an idea of what this looks
13 like. This is a fairly -- the area, it is a place
14 that is called E136, and there is a map here show.
15 This is the province of Alberta here. Here is BC
16 and Saskatchewan. This play system is a fairly
17 large system. It is a shallow gas system which
18 encompasses Eastern Alberta and Western
19 Saskatchewan, so it is fairly large, fairly
20 mature. The blue is what I call the discovered
21 pools, and then the experts think there are this
22 much pools that are yet to be discovered, and then
23 we add this third layer which is the economic
24 truncation.

25 Now we do this what is called a pool

1 size category, and this is kind of log scale. So
2 if you think of pool size six as being 1 bcf
3 pools, and then it is a log scale so that goes by
4 1 bcf, 2, 4, 8 and so on. Then on the other side,
5 it is half a bcf, a quarter, an eighth, and so on.

6 These pools can be very very small.

7 This scale, the vertical scale is also a log scale
8 as well. You see although it is not a very big
9 wedge, there is a huge number of pools there, but
10 the resource isn't very big.

11 Finding the analysis. I think I will
12 skip over the business slide here, but what I want
13 to show you here is that with finding the rate is
14 what we do we look at the historical data, and now
15 what we have here is a pool count, and what we
16 have is historical data that shows how we have
17 been discovering pools. The previous distribution
18 will give us this end point.

19 What we do then is that we then fit a
20 forecast of how we will find the future pools.
21 This bottom line, the straight line, this is the
22 pools that were found at random, it is a straight
23 line. The upper line would be it was perfect
24 foresight. So, if you found the largest pool,
25 second largest pool, and so on.

1 Basically, how we do this is for
2 example, like if we have the distribution on the
3 right hand side here, you can see that the red is
4 discovered and the yellow is the undiscovered, and
5 this should be the historical data. Again, same
6 sort of graph. What we have here is the
7 extrapolation with depending on how you do it your
8 fitting will tell you how many of these pools are
9 yet to be discovered.

10 This is for the low case. Now, if it
11 changes just a slight bit, what you will get is
12 this is for the high case here. You can see the
13 small change in slope, and you get a huge amount
14 of small pools here that will then -- that is how
15 we do our high case and our low case, and the base
16 case is something in between.

17 Now I will get to the blended supply
18 cost curve. What we do here basically -- the way
19 we define our supply cost it is basically the
20 price that is needed to achieve an eight percent
21 real pre-tax and pre-royalty return on capital.

22 What we do then is we take each supply
23 increment for supply cost, and it includes a
24 distribution of pool sizes, not all of which will
25 be economic.

1 What we do for those pools which exceed
2 the price -- I am sorry, the pools that exceed the
3 price that are not economic are not connected, and
4 then we will put them on at a later time in the
5 supply cost curve at half cycle cost. Basically,
6 just to make sure that when we are talking about
7 supply cost, we are talking about cost that don't
8 include taxes, royalties, market expenses. It is
9 simply operating and capital, like drilling costs
10 and success factors and all those kind of things
11 go into the cost side.

12 On the flow side, we take what residual
13 is being added on, and we put a flow schedule to
14 them.

15 We will skip this slide here as well.
16 So, basically, this is what happens. What we end
17 up doing is you get a supply cost curve, and this
18 is for purposes of coming up with a flow
19 projection as opposed to a supply cost that you
20 may have seen in previous presentations that are
21 used in supply and demand economics.

22 What you have here is what we call a
23 blended supply cost curve, which is somewhat
24 higher and flatter than the perfect foresight one.

25 What I do find, and this may not be a

1 very big difference, but we do find that it does
2 make a change in your supply forecast. So, then
3 what happens is once we have done this supply cost
4 curve, then this moves on to what is called a
5 supply forecasting module. This is done by region.

6 In western Canada, we use about
7 seventeen regions. Everything that I have talked
8 about is more like a long-term model. Now we have
9 a short term activity based model because as you
10 know, the long-term model is not very good at
11 doing a short-term forecast. So, we have a short-
12 term model which basically is based on the
13 infrastructure of the industry, how many rigs
14 there are, what sort of gas focus, and those sorts
15 of things which then constrain the short term.
16 Then the long term is where we use these blended
17 supply cost curves.

18 PRESIDING MEMBER GEESMAN: What period
19 of time are you trying to cover in your short-term
20 model or in your long-term model?

21 MR. DIMATTIA: The short-term model runs
22 until about 2008, but I would say that is probably
23 the results -- it is probably like a very good for
24 the three or four year outlook, but we do use it
25 for as far as eight years out.

1 The long-term model right now, well, the
2 model itself actually we have a ran it out as far
3 as 40 years. The reason for that is because for
4 depreciation calculation purposes, for economic
5 life purposes, you have to go out quite a ways
6 because what they want to do is that they want to
7 use that as an input to determine when you retire
8 facilities, and sometimes facilities they can go
9 for quite a while, so you need to come up with
10 what they call a point, like when the facilities
11 are to be retired and they go quite a ways out.

12 Basically, I think we are at the end
13 here almost. What I have noticed here with these
14 supply cost curves, with these blended supply cost
15 curves, I like them a little bit better because
16 they tend to reflect the published F & D and
17 lifting costs that certain outfits like Ross,
18 Smith, Arc Financial, and First Capital, like when
19 they report supply cost, we tend to be closer
20 using this method to that.

21 Also, we notice that with these
22 forecasts, they tend to be a bit lower, and they
23 seem a bit more closer to the forecast that we see
24 with other near term outlooks.

25 What I have included in the handout is a

1 whole pile of like all the forecasts that we have
2 here, but I won't go through them because this is
3 supposed to be talking about the methodology, so I
4 won't go through these, but they are there for
5 your reference.

6 So, that concludes what I wanted to
7 speak about.

8 MR. MAUL: Walter, could you back up to
9 slide 20 and the comparison of your forecast with
10 the NPC which I assume is National Petroleum
11 Council.

12 MR. DIMATTIA: Which one, sir?

13 MR. MAUL: 20, the next one. Go
14 forward. There you go.

15 MR. DIMATTIA: Okay.

16 MR. MAUL: Could you talk now a minute
17 about your forecast versus -- and I assume NPC is
18 National Petroleum Council?

19 MR. DIMATTIA: Yes, it is. First of
20 all, somebody snuck this one in here. The first
21 thing, I am not happy about it.

22 There is a gap here, and I was going to
23 find out why there is a gap here. This might be
24 Canada maybe I'm thinking, and this might be
25 western Canada. So, I am not sure.

1 First of all, this is our base case
2 forecast.

3 MR. BRIDGES: Well, they are both
4 western Canada, but I think it is once you
5 forecast quantity, like we are trying to forecast
6 what goes on in the pipeline, and theirs probably
7 includes some (inaudible).

8 MR. DIMATTIA: Yes, there could be a
9 differential thing. I also know that the NPC,
10 sometimes they speak of wet gas. I know that our
11 forecast is probably more dry gas. So, that might
12 be one case here.

13 Also, this forecast is fairly flat, and
14 then it falls off. This forecast also includes
15 unconventional as well. If it was just based on
16 conventional by itself, there would be a slow
17 decline starting from day one going down. I am
18 not sure of the other questions you wanted to ask
19 about this.

20 MR. MAUL: Actually, given the time
21 here, you get two bites of the apple, John gets to
22 come back after.

23 MR. BRIDGES: After lunch.

24 MR. MAUL: Yes, after lunch, yeah. I
25 have some questions for the two of you, and I

1 don't know who wants to answer it, but obviously
2 oil sands. John I notice in your presentation
3 you've got questions on oil sands, development
4 impact on demand. Maybe we can handle a bit more
5 of that later.

6 Walter, for you, obviously Canada is a
7 very important supplier to the US, it is important
8 to California particularly because we get a
9 (indiscernible) of our supply from Canada from the
10 (indiscernible) pipeline system. We need as much
11 information as we can about that. Not only to ask
12 you to provide input to our models.

13 As you know, we have a relationship with
14 you. We subscribe to SERI, and we have a
15 relationship with the National Energy Board of
16 Canada. Are there other entities we should have a
17 closer relationship with to make sure we get
18 adequate and full information and robust
19 information about Canada.

20 MR. DIMATTIA: You said which ones are
21 they again?

22 MR. MAUL: SERI, NED, and you guys are
23 three major data sources for Canada.

24 UNIDENTIFIED SPEAKER: (Inaudible).

25 MR. MAUL: And the NPC right here.

1 MR. DIMATTIA: I think you have covered
2 them. There is another sub-layer of agencies that
3 you could talk to, and we could take that off line
4 and could talk as to --

5 MR. MAUL: We also deal with the
6 individual provinces with the western gas or even
7 with the Alberta, Saskatchewan, or British
8 Columbia at the state level and the province level
9 as well.

10 MR. DIMATTIA: (Inaudible).

11 MR. MAUL: Okay, good.

12 UNIDENTIFIED SPEAKER: I do have one
13 question if I may.

14 MR. MAUL: Sure, go ahead.

15 UNIDENTIFIED SPEAKER: If you go to
16 slide 18, I want to talk about that a little bit.

17 MR. DIMATTIA: This one?

18 UNIDENTIFIED SPEAKER: Yeah,
19 (inaudible).

20 MR. DIMATTIA: The undiscovered here?

21 UNIDENTIFIED SPEAKER: And the timing of
22 when you (inaudible) and how fast it is going to
23 come (inaudible)?

24 MR. DIMATTIA: Basically, this
25 undiscovered here -- first of all, it is a break

1 down by province, and it is a breakdown by the
2 type of undiscovered. So, as far as when it is
3 coming down, I think all of these components right
4 now I would say are coming on. Like they are in
5 the forecast, but like for example, like on the
6 coalbed and methane, well, I think there is none
7 in BC at this time. There is activity but none
8 there. There is quite a bit of methane that is
9 coming on.

10 We are roughly at I am guessing about 50
11 million a day or something like that.

12 MR. BRIDGES: A little bit higher maybe,
13 70 or 80.

14 MR. DIMATTIA: Yeah.

15 MR. BRIDGES: The next slide shows that.

16 MR. DIMATTIA: The tight gas -- one
17 thing about tight gas that you have to realize
18 here too is we use a bit of -- our definition of
19 tight gas is different than the US definition. It
20 tends to be more project area and based on
21 technology, and where as I think like in the US,
22 they tend have certain areas that are dedicated as
23 tight gas. Whereas with ours, there are certain
24 areas that the producers are using different
25 techniques.

1 Tight gas right now is mostly happening
2 in Northeast Alberta, right here, and in BC. It
3 is very much a factory operation, so they try to
4 drive the cost down. As far as timing, the
5 forecast is very much like -- the rates are
6 probably tight gas forecast, I don't have the
7 exact numbers, but it is quite small.

8 Again, it is like a wedge, it is a small
9 amount, but it grows with time. You can see with
10 the total numbers here, like you have the 55 and
11 the 15 there, that is about 70 tcf there versus
12 the like the conventional.

13 What happens over time like what you
14 will see in 25 years, this will be about in terms
15 of flow, be like less than a quarter, and this
16 will be like three quarters of the flow. Right
17 now, it is like maybe 99 percent and one percent,
18 something like that.

19 MR. MAUL: Any more questions? Let me
20 suggest we take a lunch break from 12:00 and come
21 back at 1:00 from lunch.

22 (Whereupon, at 12:16 p.m., the workshop
23 was adjourned, to reconvene at 1:08 p.m.
24 this same day.)
25

1 AFTERNOON SESSION

2 1:08 p.m.

3 MR. MAUL: Commissioners, shall we
4 reconvene?

5 PRESIDING MEMBER GEESMAN: Absolutely.

6 MR. MAUL: It is 1:08 for all you folks
7 that are on the conference line, we are going to
8 reconvene now. We have John Bridges also from
9 TransCanada Pipeline talking about different
10 aspects of demand and tar sands, tight oil, the
11 whole bit, the tight sands.

12 MR. BRIDGES: Thanks very much for
13 having TransCanada up twice in one day. My
14 goodness. At the outset, I'd like to say that the
15 reason we are here is that as the new owner of gas
16 transmission in the Northwest, we would like to
17 insure that we are part of the gas industry
18 improving the robustness of the CEC natural gas
19 forecast. So, we would very much like to be part
20 of that process.

21 I think you will see as I talk about
22 demand here, and Walter has covered our supply
23 process, that we agree that with Hill Huntington
24 that prices and flows reflect economic
25 opportunities. You see that very much in Alberta

1 demand growth because of the oil sands.

2 We also agree that fuel substitution
3 occurs over a long period of time, and so much of
4 what you see in the short term out to 2010 in our
5 forecast is pretty much entrenched. There isn't a
6 lot of elasticity of demand because people can't
7 make those changes that quickly. That is
8 particularly true in the oil sands business.

9 I don't want to dwell on this slide, but
10 this first slide is to just illustrate that the
11 residential/commercial portion of demand is
12 relatively small. It is less than 25 percent and
13 that going forward from the 2003 estimate of
14 3.1Bcf a day out to 2015 where we have a 1.7 Bcf a
15 day growth. All of that growth is in the
16 industrial sector. It looks like part of it is
17 electric gen, part of it is minable or In Situ Oil
18 Sands, and we separate those. We will tell you
19 why as we go forward here. The rest of it is in
20 other industrial, but that is also related to the
21 oil sands because of upgrading at refineries and
22 heavy oil upgrades.

23 MR. MAUL: John, on that chart back
24 there of the other industrial, who are the three
25 largest sub-categories of industrial?

1 MR. BRIDGES: There is petrochemical in
2 there, both polyethylene manufacturing like Nova
3 and Dow, Nova Chemicals and Dow. There is also
4 several fertilizer companies, ammonia based
5 fertilizer, and there is a large slug of other
6 industry. We do look at all of that.

7 In our forecast process, Walter
8 mentioned that we are connected to a large number
9 of customers that are in the E & P business. Many
10 of these customers are also large users because
11 they are involved in the oil sands business.

12 There are other customers, such as I just
13 mentioned Nova Chemicals and Dow and Agrium, they
14 are our customers too. Many of the ones that are
15 connected directly to us, there are others that
16 are connected through the gas utility, through
17 Atco, but many of them are directly connected to
18 us. So, all of customers discuss their project
19 plans, their expansion plans with them, and their
20 related gas demand.

21 Part of our very important process to us
22 to get the right forecast for gas demand is to
23 develop an oil sands project time table, and that
24 is because there are so many projects that are
25 proposed that they can overlap, and there is a

1 limitation of man power in getting those projects
2 constructed.

3 The oil sands proponents themselves have
4 to be very careful of this, they have to make sure
5 that they don't try and start up two major
6 projects at the same time. Otherwise, this leads
7 to large cost overruns.

8 We developed a production forecast after
9 we have a project time table, and then we also
10 independently come up with a power generation
11 forecast, and we merge that power generation
12 forecast on a facility basis with bitumen projects
13 because many of the bitumen projects have
14 associated co-gen, so we merge those forecasts and
15 make sure that we have a consistent forecast.

16 Then I want to talk about gas intensity
17 next, which we measure s the amount of natural gas
18 or mcf per barrel of output. That gas intensity
19 is reduced over time due to two factors. One is
20 the gradual improvement in extraction techniques.
21 These project proponents naturally want to get
22 their costs down, so over time, over the next few
23 years, as a new projects come in, they are
24 continually finding methods of using less energy
25 to get the same amount of oil out of the ground.

1 That means less natural gas.

2 Going forward, we are also looking at
3 ultimate energy sources, and I'll talk about that
4 more later.

5 Two more points on other industrial
6 demand. The fertilizer demand has been reduced as
7 the cost of doing business in North America has
8 become less competitive with off shore. However,
9 they are still serving a landlocked market, and as
10 such, they can compete well with offshore ammonia.

11 Then here this point about
12 petrochemicals. The amount of petrochemicals that
13 will be produced in Alberta is partly a function
14 of a decision on northern gas and when that gas
15 comes in because that gas brings a lot of natural
16 gas liquids.

17 PRESIDING MEMBER GEESMAN: Can I ask you
18 about the project timetable? Is that advisory
19 only or are there contractual provisions or
20 regulatory provisions that makes some binding
21 attribute to it?

22 MR. BRIDGES: All of the projects have
23 to go through an application process, so of
24 course, in the early years what you would see in
25 that time table would be the results of the

1 projects in the next five years, it is pretty much
2 been determined when they are going to be doing
3 each phase of their project and when it will start
4 up. You do get some delays, but our project
5 timetable that I refer to here is more, the part
6 of it that requires some creativity if you like,
7 is after the projects that have been approved and
8 are presently under construction.

9 The ones that are under construction
10 will take us forward until 2008. So, pretty much
11 like large new projects can't get in under the
12 wire before 2010. Smaller projects such as the In
13 Situ can because there is not as much capital
14 investment, not as much construction required.

15 I just wanted to talk about some of the
16 constraints to industrial growth which in a sense,
17 when we have been talking about price elasticity
18 here, we have constraints. The foremost amongst
19 those are construction.

20 If I add up the projects that are on the
21 slate to be built over the next ten years, there
22 is roughly 55 billion dollars of investment
23 required. Over like 5 billion per year.

24 To reduce those constraints, some of the
25 solutions are that the companies are looking at is

1 that they are doing as much of the engineering up
2 front as they can to insure that there is no
3 changes mid course corrections to insure that
4 there is no overlap in these mega-projects, the
5 integrated mining projects.

6 Some of them are also looking at modular
7 construction so you can construct some of that
8 off-site rather than have to do it out in an area
9 where it is difficult to get the labor out to that
10 region.

11 The Fort McMurray region which much of
12 this oil sands business is centered is
13 undergoing -- there has been a study completed, a
14 proposal to improve the rail links to that region,
15 which therefore you could get materials up there
16 much cheaper. Also, a couple of the projects that
17 are right now in pre-approval stage, have built
18 airstrips to get the work force up there because
19 they are so far away, and if you have to locate
20 everybody in Fort McMurray where there is limited
21 housing, you know, they have a lot of difficulty
22 in getting a hold of people to do the work.

23 There is a lot of pre-planning. That is
24 my message, and that assists in overcoming this
25 construction constraint.

1 The other thing is that you have got to
2 think of heavy oil market constraints. The
3 present markets for heavy oil for Canadian heavy
4 oil are more or less saturated, but the plans are
5 to go slightly further afield, go out further into
6 the mid-west Pad 2 region, go out further into the
7 Pad 4, the Rockies region, and to access new
8 markets. You can do that through building new
9 pipelines.

10 There is talk of a new deep water port
11 off the west coast of Canada. They could then
12 take heavy crude from there to California where
13 California's need for heavy oil, imported oil, are
14 increasing as their own resource here declines,
15 and A & S crude is in decline as well. That is a
16 potential market, and the Far East has a large
17 appetite. There is a lot of discussions about
18 China being interested in a secure source of crude
19 oil.

20 Heavy oil market constraints are
21 foremost in our mind, and then another way of
22 creating new markets for heavy oil is to install
23 new coking capacity, and that is being pursued
24 both in the midwest deal signed by Incana as
25 looking as a partnership to put in coking capacity

1 at Primcor. You could also put in the coking
2 capacity in Canada itself, so you can change the
3 amount of light oil that you use and use heavy oil
4 instead.

5 Energy costs, that might be more along
6 the line of the demand flexibility or the demand
7 constraints that we are talking about for natural
8 gas. So, will gas be more expensive than oil. We
9 don't think so going forward, we think the two are
10 related, but one of the solutions to controlling
11 your energy costs are to reduce your gas
12 intensity, improve your extraction techniques,
13 improve your processing, and then finally, last
14 but not least is to use other forms of energy.
15 They are looking at that.

16 Longer term our gas price and I think
17 many other gas price forecasts indicate that it is
18 related to oil products. So, oil products, oil
19 sands projects actually benefit from higher oil
20 prices. So, if you use 1 mcf gas produce a barrel
21 of oil, and the barrel of oil goes up six dollars
22 a barrel, and the price of gas goes up one dollar
23 per mcf, actually, you are further ahead. It is
24 improved economics. That makes it relatively
25 inelastic to pricing.

1 This chart is an illustration of where
2 we see gas prices going relative to oil products,
3 so we compared at a market where gas competes with
4 oil products, so the lower line, the dotted line
5 is one percent residual fuel oil, and you can see
6 that in the past, through the '90's, gas on an
7 annual average basis, was closer to residual fuel
8 oil.

9 As we moved into 2001, gas prices spiked
10 and came up to and were equivalent to the cost of
11 No. 2 heating oil or middle distillate. That is
12 the green line is middle distillate.

13 Prices fell back again in 2002, but then
14 currently the price of gas has gone up again, and
15 so we think going forward that we will see natural
16 gas much closer to the price of middle distillate
17 going forward. There has been a shift.

18 However, going back to that last point
19 about oil sands projects, what we are really
20 saying is that there is some tie, so we don't see
21 a disconnect between oil and gas prices longer
22 term.

23 Turning now to a couple of other
24 industrial sectors. I touched on this earlier,
25 both petrochemicals and fertilizer will as far a

1 petrochemicals is concerned, will gas being more
2 expensive in products, we don't think so. Nova
3 Chemicals is in the top quartile of productivity
4 relative to others in its business.

5 Size is very much a factor in the
6 petrochemical business, and they have some huge
7 plants there, Jophry, so we think that if
8 petrochemical producers in North America are to
9 shut down, they will be shutting down on the Gulf
10 Coast rather than in Alberta.

11 The profitability of the petrochemical
12 producers is based on their margin, the margin of
13 polyethylene to the price of natural gas, which
14 establishes the price of ethane that goes into
15 making ethylene and then polyethylene. This
16 margin strengthens as the world-wide utilization
17 capacity increases. Right now that utilization of
18 capacity is high, and so it is not the price of
19 natural gas that concerns them, it is this margin.

20 Longer term, new sources of gas are
21 required in order to have that liquid extraction.
22 With Northern gas, we would see increased liquids
23 extraction, and that would provide an opportunity
24 for the petrochemical business to expand. In our
25 forecast, we have relatively flat petrochemical

1 demand until Northern gas comes in.

2 On the fertilizer side, the issue there
3 is it going to be produced domestically versus
4 offshore. Our big producers of fertilizer,
5 Agrium, Canadian Fertilizers produce ammonia based
6 fertilizers. They produce close to land-locked
7 markets, so they have a transportation advantage
8 in their products. So, cost is an issue for them,
9 but they do have a locked in advantage. They are
10 very much concerned about the cost of gas. So, in
11 our forecast, longer term with higher prices, we
12 would see fertilizer production certainly not
13 increasing and perhaps declining with higher gas
14 prices.

15 COMMISSIONER BOYD: I may have missed
16 your definition of Northern gas, does that mean
17 McKenzie Delta Gas or (indiscernible)?

18 MR. BRIDGES: It includes all of the
19 sources of natural gas. Right now, McKenzie Delta
20 is the one that is in our base case going forward.
21 We see that coming on in November 2009. Of
22 course, there is a potential for Alaska gas, and
23 if that Alaska gas comes in, it contains a lot of
24 gas liquids.

25 Turning now to electric generation.

1 Much of the generation is associated with oil
2 sands activity because of the economics of cogen.
3 In the 1999 to 2004 period, there was a big shift
4 to natural gas fired capacity. You can see from
5 the chart that follows that lower area, which is
6 the capacity of natural gas fired plants increased
7 from roughly 2,000 to 5,000 MW of capacity.

8 So, going back to this slide, what we
9 are seeing is that it now represents 42 percent of
10 the share. Its benefits are lower emissions than
11 from coal plants, lower capital cost to build, and
12 of course, you get this cogen efficiency because
13 the oil sand projects need steam. So, you can
14 create steam at the same time as you can create
15 surface electricity.

16 There is a transmission constraints. We
17 can't realize the full potential of attaching
18 cogen to all the oil sands plants unless there is
19 more export transmission capacity. So, we've been
20 working on that to look at opportunities, but our
21 forecast doesn't include that in our base case.
22 We are just assuming no more export capacity.

23 In the short term, the next five years,
24 2005-2010, there are a few new natural gas cogen
25 plants that are being built associated with oil

1 sands. There is new coal plant capacity. In both
2 of those sectors, there is also retirements going
3 on of less efficient coal capacity and less
4 efficient gas fired capacity.

5 If you look at that chart again, the gas
6 capacity doesn't appear to change. What is
7 happening, though, is that there is more gas use
8 at that capacity because it is fairly low load
9 factors in 2004. The coal fleet which is the
10 majority of gas fired capacity in Alberta is well
11 utilized as well is hydro.

12 Going forward, we will see improved
13 utilization of the gas plants and some new coal
14 and new gas. In the last five year period here,
15 we are showing new synthetic gas applications and
16 new wind applications coming in. I'll talk about
17 that shortly with regard to the synthetic gas.

18 Other assumptions industrial area is
19 that the manufacturing activity is related to
20 economic growth. We haven't done a regression
21 analysis that we saw before lunch, but GDP growth
22 in alberta is around 3 1/2 percent, and it is one
23 of the fastest in Canada. It is related to the
24 oil sands and spin off effects from the oil sands,
25 and there are definite advantages to manufacturing

1 businesses to locate in Alberta. We believe that
2 we will see continued gas demand growth for the
3 industrial sector.

4 In the core market, I am not going to
5 dwell on this, just three lines. Basically, long
6 term population growth has been 2 1/2 percent pa,
7 quite rapid growth. We see the same rate of
8 growth going forward, but because of residential
9 efficiency gains, we believe that the demand
10 growth in the residential sector will only be one
11 percent. Commercial demand is growing somewhat
12 faster than residential because of the GDP growth,
13 so we will see it slightly higher, maybe 1.2
14 percent commercial growth.

15 Let me just turn to oil sands again,
16 show you the result of our staged forecast and
17 quite coincidentally, some time after we completed
18 our forecast we saw the Canadian Association of
19 Petroleum Producers forecast for oil sands
20 production. They had gone to their members and
21 asked them what their plans were and then they
22 scaled back some of those plans going forward
23 because there were too many projects in this time
24 frame.

25 The result you can see is remarkably

1 similar to our independent forecast, which gives
2 me some comfort we will in fact see an increase in
3 oil sands production from the million barrel a day
4 level that it is in 2004 up to about 2 1/2 million
5 barrels a day. So, 150 percent increase over the
6 next twelve years.

7 MR. MAUL: John, you have seen a fairly
8 robust pick up in the pace of oil sands
9 development in the last couple of years. You
10 expect that to continue for a few years to come?

11 MR. BRIDGES: Yeah, it probably began
12 back in 2001-2002 with Suncor expansion and it was
13 the new (indiscernible) Project which is a
14 consortium that is led by Shell and Syncrude is
15 finishing up a major 50 percent expansion which
16 will be complete next year. So, it started back
17 in 2001, you can see it was fairly flat to 2000.
18 We have moved from roughly 600,000 barrels a day
19 to the million barrel a day level.

20 The projects that are currently under
21 construction will if you stopped any new projects,
22 you would still be at this level by 2008. All
23 these projects are in the pipe. They are being
24 built right now. Interestingly enough, they are
25 all based on using natural gas, which is not

1 necessarily what we will see going forward.

2 I have summarized the oil sand demand
3 and included the additional upgrading demand that
4 is off site. These first two segments are the
5 demand for gas at the mining projects and at the
6 institute projects. If you add up all of that
7 demand for oil sands, it is roughly 1.3 bcf a day.

8 Going forward, we do see a number of
9 factors that come into play which will change
10 that. I just wanted to go over the oil sands
11 base. If you look at the oil sands, there is 175
12 billion barrels of established reserves that is
13 recognized by the EIA as well. It was in their
14 outlook.

15 About 20 percent of that can be reached
16 by mining techniques, which means that you can
17 actually mine down to about 75 meters or 250 feet.
18 Deeper than that, you have to use in situ or in
19 place techniques, and that is significant from a
20 point of view of energy demand.

21 These projects in blue are I think all
22 of the mining projects that we are aware of. You
23 can see they are centered north of Fort McMurray.
24 They are near the Atabaska River which runs
25 through the middle of it here, and their shallow

1 oil sands deposits.

2 The in situ is deeper than this 250 feet
3 and they are scattered more across this Northeast
4 region, and you can see 80 percent of the
5 established reserves are in situ. They tend to be
6 smaller projects. When we talk about Syncrude,
7 Suncor, they are now up to their 250,000 barrel a
8 day range.

9 A new project such as the CNRL Horizon
10 Project, the planned capacity will be 230,000
11 barrels a day.

12 When you plan a project such as Jack
13 Fish or McKai River, Petra Canada, they are 30,000
14 barrel a day range. So, there is less investment
15 required, and they are more manageable from an
16 investment point of view, more manageable from a
17 construction timetable point of view.

18 MR. BRATHIWAITE: John, before you leave
19 that, that 175 billion barrels is all of that is
20 recoverable?

21 MR. BRIDGES: Yes, this is the
22 established reserves that can be recovered using
23 today's technology at today's prices.

24 MR. BRATHIWAITE: Do you have any feel
25 for what is in place?

1 MR. BRIDGES: Yes, it's over one
2 trillion barrels.

3 MR. BRATHIWAITE: Thank you.

4 MR. BRIDGES: We had talked about there
5 being -- I've seen other figures around 300
6 billion barrels, and over time, this number will
7 probably increase in terms of what is recoverable.
8 Right now, CAP talks about there being 175 billion
9 barrels, the EUB, Alberta Energy Utilities Board,
10 they are the one that came up with these two
11 figures, the 32 and 143.

12 A quick picture, just shows you the oil
13 sands, so the oil is contained with sand, and then
14 after extraction through mining or through in situ
15 methods, you are left with this black tarry
16 substance that basically is the consistency of
17 asphalt on the road. It has to be heated to be
18 moved, and it would have to be diluted if you
19 wanted to move it in conventional pipelines.

20 After processing, you can come up with a
21 synthetic crude oil, and that is what the three
22 integrated mining projects do now, the ones that I
23 mentioned. That lighter stuff material is
24 suitable for conventional light crude refineries.

25 In situ production, (indiscernible)

1 process on the left, mining production, both of
2 them can shift their product to an independent
3 upgrader, or on the right here, we show Suncor's
4 picture of their integrated operation.

5 Now Syncrude is integrated just like
6 Suncor, I was just using pictures here to show
7 that you can mine it. You can use the in situ the
8 process, you can move it to an off site upgrader.
9 The Afabaska Project upgrader is located near
10 Edmundson as opposed to the location of the Muskeg
11 River Mine which is way north of Fort McMurray.

12 You can take the products, move it to
13 heavy crude refineries through blending it. We
14 call that bitumen blends, or you can process it at
15 these two here to produce synthetic crude oil.
16 That then can move to conventional light
17 refineries.

18 Why I am going through this, I am sorry
19 if it is laborious. It may seem a bit long
20 winded, is that with the rising natural gas price
21 forecast, there are other methods that people are
22 thinking of using of processing, extraction and
23 processing.

24 Nexen/OPTI have begun construction of
25 the Long Lake Project which will produce 60,000

1 barrels of day of synthetic crude oil. They are
2 not going to use very much natural gas at all. In
3 fact, their energy is going to be based on using
4 the bottom end of the bitumen barrel, so they are
5 going to take the asphaltenes in the bitumen,
6 extract them, which leaves them with a lighter
7 bitumen.

8 We think that post 2010, we are going to
9 see more of that. There are two promising
10 methods. There are many more, but I have just
11 picked on two here, bitumen gasification, which
12 will be used by Nexen/OPTI. We associate that
13 more with in situ projects because they have the
14 bitumen on site.

15 Now mining projects also have the
16 bitumen on site, so I am not saying it is
17 exclusively for In Situ projects.

18 Coke is a product of the integrated
19 mining projects. They reject (indiscernible)
20 carbon, so they have a lot of coke on site, and
21 you can gasify that too. Basically, the coal
22 gasification technology is a much cleaner way, so
23 when we talk about the IGCC process, that has
24 applications in the oil sands.

25 Of course, there are uncertainty around

1 the timing and the extent, but we do see it taking
2 time. So, in terms of demand elasticity, it is
3 not going to happen in the next five years, and
4 what we wind up here, is you could call this
5 technological change, but you can see your gas
6 intensity for In Situ projects which is currently
7 around 1.2 is going to improve even without the
8 application of new technology to around .8 or .9
9 by 2010, so this is a forgone conclusion as they
10 use new efficiencies. Going forward, the next ten
11 years we are counting on improvements.

12 MS. KHOSROWJAH: How about the cost of
13 the production, is it cost effective?

14 MR. BRIDGES: That is where the price of
15 natural gas is important, so --

16 MS. KHOSROWJAH: As this one is not.

17 MR. BRIDGES: At this point, we believe
18 that when you use forecast price in excess of \$4,
19 that it is economic. If your forecast price is
20 less than \$4, then it wouldn't be.

21 Improvements in both of those processes
22 going forward and why that it is important is
23 because in our forecast here, these two bars,
24 these two areas are the demand for gas for In
25 Situ, the demand for gas for mining in our

1 forecast.

2 You will recall that we had oil
3 production rising, continuing to rise and after
4 2015, we see it rising further.

5 If you use the existing technology, the
6 same kind of ratios you have today, you would have
7 a huge increase in gas demand. So, that is why we
8 think technology is so important to bring that
9 down. There will be a saving through that change.
10 That maybe is demand elasticity.

11 Just want to finish up with the
12 comparison of the NPC forecast to ours. It seems
13 that maybe they are using a slightly different
14 starting point than us. Again, it may be similar
15 to that what we saw when Walter showed the WCSB's
16 supply. They may be using some more of the lease
17 and plant fuel in their forecast.

18 We start on a slightly lower point, and
19 we found if you had used half of the future oil
20 sands projects and added them into their forecast,
21 which is this red line, their balance future case,
22 that we would in fact be parallel.

23 I can't speak to the content of the NPC
24 forecast, suffice it to say they may be using more
25 demand destruction or demand elasticity than we

1 are.

2 That was it. Thank you.

3 MR. MAUL: Thank you, John.

4 COMMISSIONER BOYD: No questions since
5 Mr. Maul and I have been up there and seen that.
6 We are very impressed with it.

7 MR. BRIDGES: Impressive, isn't it?

8 MR. MAUL: John, a few questions for us.
9 Between you and Walter, you didn't say much about
10 coalbed methane, which is also a very large
11 potential resource in Canada. What are your
12 expectations of that and how do we model that as
13 an input assumption for us?

14 MR. BRIDGES: There was a slide in
15 there, wasn't there, Walter?

16 MR. DIMATTIA: Yes, there was.

17 MR. BRIDGES: That said unconventional
18 gas, and most of that is coalbed methane. We
19 should maybe take that off line and --

20 MR. DIMATTIA: (Inaudible). Just a
21 quick answer to that, the coalbed methane, because
22 it is a new resource, we don't have as much data
23 as we would like. Right now for supply cost
24 curves, we are using the Black basin as an analog
25 right now, but we are using a short-term activity

1 model. So, it is somewhat similar to what we use
2 on the conventional side.

3 MR. GOPAL: You think the numbers that
4 you have is very different from NPC numbers? NPC
5 does have some coalbed methane in their numbers.

6 MR. DIMATTIA: For Canada?

7 MR. BRATHIWAITE: Yes, for Canada, yes.

8 MR. DIMATTIA: I haven't seen those
9 numbers. I'll have to check that to see how
10 different they are. I think they are somewhat
11 more optimistic but I am not sure. Our numbers
12 are a bit more optimistic, but I'll check that.

13 MR. GOPAL: We would really like to get
14 your input on this because this is some
15 information that we put into our model. So,
16 whatever input you guys have on this would be very
17 helpful for us.

18 MR. DIMATTIA: We have some nice detail
19 spreadsheets there.

20 MR. MAUL: The effects you presented on
21 the oil sands development and therefore the gas
22 demand for oil sands actually provides much more
23 certainty in the near term than we had previously
24 assumed. So, that has been very helpful for us.
25 Although, longer term is a little more uncertain,

1 it is very helpful.

2 If you take all that together, what do
3 you think the net export of gas from Canada to the
4 US is going to look like? Is it going to be
5 increasing, decreasing, staying flat over the next
6 ten, fifteen, or twenty years?

7 MR. BRIDGES: Well, until Northern gas
8 comes on, there will be some decrease. We've got
9 1.7 of demand growth for Alberta, and we have
10 relatively flat supply, but we do have McKenzie
11 Delta coming in, so at that time, we will be
12 getting back to today's levels of exports.

13 UNIDENTIFIED SPEAKER: What do you have
14 on the books as far as projecting the advances in
15 technology to reduce the amount of gas used in
16 that process? Can you tell us anything on what
17 those technologies are, or do they have an idea,
18 do you know what they are going to do, or is it
19 just projected they will figure out something
20 later?

21 MR. BRIDGES: No, there has been a fair
22 amount of work done on this. I am certainly not
23 the expert. The reason we included in our
24 forecast this year is because we saw the body of
25 work that was being put together and also industry

1 beginning to move big investment by Nexen/OPTI in
2 employing this virtually gasless process.

3 I can refer you to the Alberta Chamber
4 of Resources or Alberta Chamber of Commerce
5 website. I think it is the Alberta Chamber of
6 Resources, and if you -- I'll get you the website
7 for that, and they've got a very good report that
8 was published in January that deals with
9 technological change in the oil sands.

10 MR. MAUL: Howard, your question?

11 UNIDENTIFIED SPEAKER: Just to clarify
12 your statement about the Northern gas actually
13 increasing the activity (indiscernible) chemicals
14 in Alberta. The new pipeline for your wet gas
15 pipeline with the assumption it is distributing
16 the (indiscernible) in Alberta rather than the on
17 the Norm or not?

18 MR. BRIDGES: As far as the McKenzie
19 Delta producers are concerned. They are putting
20 in facilities to gather liquid such as coninsate,
21 so they will have a separate liquids line. They
22 will build a line down to Norman Wells and move
23 that down there.

24 When I talk about natural gas liquids, I
25 am talking about principally ethane with a small

1 amount of propane.

2 UNIDENTIFIED SPEAKER: The assumption
3 that that distributing is going to happen up near
4 the wellhead, is that true or (inaudible)?

5 MR. BRIDGES: Well, the ethane will be
6 difficult to move in a liquids pipeline. So, the
7 answer is that would happen closer to the market
8 place.

9 UNIDENTIFIED SPEAKER: Has there been an
10 assessment done of the ecological implications of
11 the oil sands, and who would be handling the
12 controls on that?

13 MR. BRIDGES: Each project has to go
14 through an environmental assessment. They submit
15 those environmental impact statements and reports
16 to the Alberta Energy and Utilities Board. So,
17 when you look at their applications, you can get
18 that material if you go on the Albert, the EUB
19 website, you will be able to find that.

20 UNIDENTIFIED SPEAKER: Are there
21 challenges to the work that is being done?

22 MR. BRIDGES: I don't know about
23 challenges, but I am not an environmental expert.
24 Certainly there are challenges to the oil sands
25 business in terms of the footprint, the mining

1 project leaves. I think one of the big issues
2 that we have to face is the amount of water that
3 is required, so water is an issue.

4 MR. MAUL: John, thank you very much.
5 Walter, also, thank you for TransCanada, we are
6 looking forward to seeing more of you down here
7 since you now have the pipeline both to the north
8 and the south of us.

9 All right, our next speaker is Katy
10 Elder from R W Beck, and you will offer even a
11 different perspective on gas modeling.

12 MS. ELDER: Good afternoon. I'm going
13 to hopefully be pretty brief and really wanted to
14 give you some more of a practical perspective with
15 some of the work that we are doing with our
16 clients.

17 I will just tell you really briefly by
18 way of introduction, RW Beck is an engineering
19 consulting firm that has been in business for
20 about sixty years. They have done a lot of work
21 across the country with municipal utilities
22 particularly, especially I am in charge, as
23 Practice Leader over its Natural Gas and Fuels
24 Practice, I am in charge of its market analysis
25 with respect to fuels.

1 That market analysis gets incorporated
2 into power price projections, financial proformas,
3 probablistic asset evaluations that are being used
4 by financial institutions, project developers,
5 banks, a variety of different people who are
6 looking at those kinds of issues.

7 The perspective that I bring to gas
8 price modeling is in some respects is very much a
9 roll up the sleeves and see what I can do with it
10 kind of perspective. I was foolish enough or
11 audacious enough, I'm not sure which one, the
12 answer is as a graduate student to think that I
13 could model residential gas demand for a small
14 utility in Massachusetts and had a lot of fun
15 doing that.

16 Despite the fact that I have done lots
17 of policy work over the years, I keep coming back
18 to trying and figure out what can I do that is
19 really simple that is useful and gives people
20 insight. So, that is fundamentally what I am
21 trying to do.

22 We have built a model that forecasts
23 natural gas prices. It goes 20 years. It has
24 both a short and a long term kind of component to
25 it. In a sense that we use a frequent update, a

1 quarterly update, to try to capture the short-term
2 nuances in the market.

3 The philosophy is try to focus on the
4 things that are really simple, but that really
5 matter, not capture every detail on every nuance,
6 try not to get so much detail in some of the
7 inputs that we are getting more finite in the
8 input than we have got noise in the market that we
9 can define around.

10 You can find, if you are interested, you
11 can find what we call the one-page quick summary
12 of the forecast. It is on our website,
13 rwbeck.com/energyforecast. It will give you a
14 picture of what the long-term and the short-term
15 forecasts are, as well as the number of details
16 around, explanatory details, around that forecast.

17 That being said, given that is on the
18 web, what you can infer from that is my goal is
19 not to be selling copies of that particular
20 document, but instead to offer that as information
21 for people who are interested. We are much more
22 interested in working with people that develop
23 their insight about the outlook.

24 We are using as an input to that a model
25 from George Lippman, George Lippman's Consulting

1 Group down in El Paso, Texas that actually
2 projects natural gas production. George kind of
3 applied a similar approach to what I did, which is
4 to roll up his sleeves and say I think I can
5 develop a pretty good model that adds insight to
6 the market, and we are using that model because it
7 is one of the few that will give us timely data
8 about production, actual production, as well as
9 drilling trends.

10 We can aggregate it by base and/or by
11 state, that sometimes gets to be important. If
12 you are looking at New Mexico and you want to
13 differentiate between the Permian Basin and the
14 San Juan Basin as an example. It also gives us
15 the ability to do some "what if" testing on
16 drilling rates if I want to change the drilling
17 rates, and the Gulf of Mexico versus the rate for
18 drilling in Alberta. I can do that with George's
19 model and we will see what the changes are and the
20 amount of production that I can expect and when it
21 comes on line.

22 What I really wanted to about was not so
23 much our approach to modeling, but this sort of
24 more practical question that comes us constantly
25 in the work that I do. I know that Jarlam and

1 Dave and the staff here have gotten this question
2 too. Jariam sort of alluded to it a little bit
3 earlier in talking about is well, is one of the
4 ways that I might fix my short-term modeling
5 problem on top of my long-term model, am I am
6 imposing a forward curve in the early part of the
7 model.

8 While Hill might give you the answer,
9 yeah, that is reasonable, I would say, no, don't
10 do that with some emphasis and passion around it
11 or cringing as the case may be.

12 People often ask me if I've benchmarked
13 my forecast with the forward market, and I used to
14 sort of look at them and go, why would I do that.
15 Now I just tell them, yes. The distinction being
16 that I look at what is going on in the forecast in
17 a forward market, but it is not an explicit input
18 to our forecast.

19 More importantly what this table shows
20 you, and I just picked a few dates over the course
21 of the last quarter during which on any given day,
22 the 12-Month Strip may have been as different from
23 I think 6.60 on December 10 to a 12-Month average
24 Strip price at 7.81 on October 22. Now, which one
25 of those was I supposed to use to benchmark my

1 forecast?

2 MR. BRATHIWAITE: The expectation which
3 ever one you want to choose.

4 MS. ELDER: That is what I would like
5 not to do. You hit that nail on the head, and I
6 think a lot of folks will do that, they will pick
7 the one that most matches their expectations any
8 way.

9 I actually worked with a client recently
10 on an integrated resource plan where they had
11 taken their own view of current short-term markets
12 and put on top of that EIA's escalation rate. The
13 question to me was that a reasonable thing to do.
14 I said, no, that is not reasonable. We can do
15 better than that.

16 I like to tell people, especially who
17 tell me that well, Katy, the forwards of a market,
18 why are you different than the market. Well, the
19 forwards are "a" market, but they are not "the"
20 market. I would like to remind them that spot
21 prices represent the cash market. The real
22 purpose of forward prices is to hedge cash. Not
23 only that, you need to recognize what ever is on
24 that forward today is going to change. The
25 forward market represents a series of negotiations

1 over time that occur when that market finally
2 closes.

3 The price is up to the close date don't
4 really matter to me unless I am going to enter in
5 to a transaction. The fact I could enter into
6 that transaction also means I might not enter into
7 that transaction. If I am evaluating
8 transactions, it could be useful to look at, but
9 it doesn't affect my view of the spot market going
10 forward.

11 MR. BRATHIWAITE: Don't you think those
12 markets give you price discovery information?

13 MS. ELDER: They give me price discovery
14 information about deals I could do if I were
15 willing to do them today. Tomorrow there will be
16 a different set of deals I could do if I were
17 willing to do them tomorrow.

18 MR. BRATHIWAITE: I do accept that, but
19 at your last point, you seemed to suggest that the
20 information that you get from it is not as
21 important as the fact that you didn't do a deal.

22 MS. ELDER: It can be useful for knowing
23 that it is there and for knowing what you could
24 do, but I think it is really important for people
25 to form their own opinion about the market and to

1 do their own research, and not be -- let me go on,
2 I think you will see more of what I am getting at.

3 MR. BRATHIWAITE: Oh sure, I am sorry.

4 MS. ELDER: There are a couple of
5 specific times that it is important to look at
6 what is in the forward market, so I just want to
7 sound like I am dismissing it entirely. If you
8 are evaluating a trading portfolio and you are
9 trying to develop a no arbitrage, zero arbitrage
10 portfolio in the short term, you may very well
11 need to be looking at forward prices and what you
12 can do with them.

13 Likewise, if you are doing a financial
14 proforma, and you have bought a hedge, you would
15 want to reflect the value of the hedge in that
16 proforma rather than spot prices that you are not
17 going to incur. You would at that point know the
18 cost you are going to incur, so you should reflect
19 that.

20 The key thing is that it will go on, and
21 Hill Huntington did allude to this a little bit is
22 that over time, you can see the liquidity on
23 NYMEX, the open interest in contracts decline
24 rather precipitously over time. There are if you
25 extended this chart out past January '07, you

1 would see in another couple of years, you will get
2 to months where there is virtually zero open
3 interest.

4 I have trouble viewing prices as being
5 transparent and discoverable when there are no
6 contracts behind those prices. So, that is one of
7 the things that drives me just a little bit nuts.

8 The other thing that I often point out
9 to people is that the forward market is really
10 different in the sense that the kinds of players
11 that are active in that market, are looking at the
12 combination of long and short positions in their
13 portfolio and in their individual trading book.
14 They are not the same people that are out buying
15 gas necessarily every day. They've got the
16 trading position set up to offset each other over
17 time. Their risk profiles fundamentally different
18 than that of the average gas consumer.

19 An illustration of this. I remember
20 quite vividly when I was involved with some of the
21 power contracts for CERS, and we were trying to
22 renegotiate one of those contracts, and the answer
23 from one of the counterparties about why they
24 couldn't renegotiate the price was they had
25 already hedged the gas.

1 First off, I said there is nothing in
2 the contract that says if you hedge the gas, I'm
3 responsible for your hedge first off. Secondly,
4 they did that because they have a different
5 perception of risk. They felt compelled to go out
6 and sluff off counteract, take the opposite
7 position on that risk. It is different than what
8 we consumers were doing where we were taking spot
9 index risk for gas under those contracts.

10 It is also important I think to
11 recognize, and I think this is something that is
12 coming out, getting a lot more emphasis in the
13 trade press, particularly some in the popular
14 press, in the last couple of months, and that is
15 the difference in behavior between commercial
16 traders and non-commercial traders.

17 Sometimes the non-commercial traders are
18 called the hedge funds. I don't know for sure
19 that they are all just hedge funds, but commodity
20 features trading commission, commercial traders
21 are those are engaged in business activities that
22 are hedged by the use of those features and
23 options markets. They are not entities that are
24 just buying positions on either side. Whereas the
25 non-commercial traders may in fact be doing that

1 for reasons of their own.

2 What I can tell you is that some
3 preliminary analysis that we have done, suggests
4 that the trading activity conducting by the non-
5 commercial traders is fundamentally different from
6 that of the commercial traders. In other words,
7 if I impose a test of statistical significance,
8 the one trade pattern versus the other trading
9 pattern, also virtually zero probability that they
10 are the same by chance. They appear to be totally
11 different.

12 The next step in that analysis needs to
13 be to go and figure out okay, they are different,
14 it is nice that they are different. Is the fact
15 that they are different having an impact on price.
16 There are a lot of people around the country
17 taking a look at that right now. I hope that in a
18 couple of weeks I will have something more
19 interesting or definitive to say about that.

20 Forwards forecasts. Lots of times
21 people feeling that the forwards of a market, I
22 can't do any better in the market, therefore, I
23 will just use the forward prices as a forecast.
24 First off, technically, and I've put this point at
25 the bottom, the technical point at the point, I

1 probably should have put it at the top.

2 Forwards are not the expected spot
3 price, they are the expected spot price adjusted
4 for risk. Now your next question will be, whose
5 risk. Well, the risk of the players in that
6 market.

7 You've got the fact that you've got
8 different players in the market, they've got a
9 different risk profile, you've got these highly
10 specialized technical trading entities who have
11 different interests than perhaps you and I do.
12 Lack of liquidity beyond the near months, the
13 notion that the forward price is really represent
14 a series of trade that culminate in a price that
15 is set when the prompt month really closes.

16 The other thing to point out is that
17 people will tell you, especially the Academic
18 Review would tell you a market is cointegrated, is
19 efficient when the future prices converge on the
20 spot price if that market closed.

21 A lot of the last ten years, that has
22 happened. You will frequently see that on a day
23 that NYMEX closes, the futures prices will get
24 very close to what the spot price is or equal to
25 what the spot price is or equal with the spot

1 price.

2 Last month it didn't happen. In fact
3 the spread between futures and spot has gotten to
4 be so wide in the last few months, that Gas Daily
5 is now publishing a table every day that shows the
6 spread. I believe the spread for most of the last
7 six to eight weeks had been well over a \$1 for
8 mmbtu. So, a huge spread difference between
9 futures and spot.

10 Another thing that often comes up is
11 whether there are forecasts of forward prices.
12 There are. You have various quantitative techniques
13 that you can apply to forward prices and spot
14 prices in order to create a forecast, a so-called
15 forecast of forward prices. Those are very often
16 used by traders in order to create this risk-free
17 portfolio, but there is something fundamentally
18 different than what we are doing and trying to
19 predict cash prices at Henry Hub every month.

20 Here is my closing thoughts for you, the
21 message that I would really like for you to
22 remember in thinking about this. That is when you
23 look at your forecast and it is significantly
24 different than what the futures curve 12-Month
25 Strip or whatever strip you are looking at today

1 happens to be significant, and somebody says, what
2 are you thinking. The answer is well, what I am
3 thinking is that those forwards are going to
4 change to meet my spot forecast.

5 That is true if I really believe my spot
6 forecast. In other words, by the time the prompt
7 month closes, those forward prices should have
8 converged to my spot forecast, or I didn't do a
9 very good job forecasting spot.

10 The second thing that I would say is
11 that really means to quote a book from many years
12 ago, don't panic. Don't be intimidated when your
13 spot forecast is different than today's forwards
14 or whatever tomorrow's forwards happen to be or
15 six months from now. As long as you have good
16 underlying knowledge, logic, you have tested some
17 different scenarios, you have looked at the
18 fundamentals, and you have a compelling view of
19 the market and a story. Hill mentioned that
20 concept too, a story that you can tell to get from
21 the short-term to the long-term, then go ahead and
22 let your forecast be different from the forwards
23 and say, that's my view of the world.

24 MR. BRATHIWAITE: May I ask a question?

25 MS. ELDER: Yes, you may.

1 MR. BRATHIWAITE: If we believe that we
2 can beat the market in terms of our forecasting
3 abilities, won't we all be billionaires still in
4 the Caribbean enjoying our pina coladas?

5 MS. ELDER: I have used that line with
6 bankers so many times. If I could tell you exactly
7 what prices were going to be, I wouldn't be doing
8 this, I would be in Las Vegas. The bankers always
9 understand that, the answer.

10 We are pretty pleased with the track
11 record that we are creating, but one of the things
12 that I will also say about forecasting or good
13 forecasting in my opinion is that there are a lot
14 of variables that are involved that you can't know
15 the real value of. What you are trying to do is
16 look at enough market information that you can
17 make an educated story or an educated guess about
18 what the value of those hidden variables are.

19 Early this year -- I have two versions
20 of my model, one that has oil prices in it and one
21 that doesn't.

22 I get somewhat schizophrenic about which
23 one I like to use to be honest about it. Had I
24 put oil prices in it in the second quarter, I
25 would have been spot on. Instead, I was 50 cents

1 off, all due to oil prices. Does that help?

2 MR. BRATHIWAITE: Somewhat.

3 MR. GOPAL: The second point when you
4 talk about spot forecast. Is the spot forecasting
5 sooner than move to a futures?

6 MS. ELDER: No, they are distinctly
7 different in the sense that spot forecasts of the
8 cash market, and the futures are of the forward
9 market.

10 MR. GOPAL: Yeah, but if you try to
11 forecast a spot, isn't that the futures market as
12 you see the futures today. If you look at the
13 forwards, does that not tell you the forecast of
14 the spot at some other time than right now?

15 MS. ELDER: Technically speaking,
16 futures or forwards are by definition, the
17 expected value of spot prices adjusted for risk,
18 but then you are going to get into questions about
19 whose risk, how is that risk measured, how is that
20 risk evaluation change over time, etc. etc. That
21 is part of what a good forecaster needs to think
22 about is whether the risks in the market that
23 would affect that.

24 MR. MAUL: Commissioners, questions?

25 PRESIDING MEMBER GEESMAN: Have you been

1 involved in advising any of your municipal utility
2 clients on acquisition of natural gas reserves?

3 MS. ELDER: We had some discussions with
4 them, but I couldn't tell you that we are actively
5 advising any of them on that issue.

6 PRESIDING MEMBER GEESMAN: What about
7 advising them on supply portfolio purchases?

8 MS. ELDER: Yeah.

9 PRESIDING MEMBER GEESMAN: Do you find
10 that they do more transactions when your forecast
11 converges with the futures price or fewer
12 transactions?

13 MS. ELDER: I would say I don't think
14 that those two things affect when they do their
15 purchases. I think a lot of what they are looking
16 at in many respects is how to get greater
17 certainty around their fuel costs, and their
18 reaction to that may vary depending on what their
19 risk aversion level is with respect to their own
20 citizen ratepayers. Some of them will be very
21 averse but aren't interested in talking about
22 hedges, aren't interested -- they have an implicit
23 concern or fear of financial instruments. Some
24 are much more comfortable going out and buying
25 long-term reserves and holding those, and

1 certainly some of the gang in California is known
2 to be looking at that.

3 It really depends on kind of their
4 history and what matters most to them. I would
5 say that the price forecast itself is not
6 indicative.

7 UNIDENTIFIED SPEAKER: In support of
8 your position, markets for more public information
9 is available like the gold market, it is very
10 clear that there are two completely different
11 classes of people who buy futures. Right now, for
12 example, the commercial hedgers, the people who
13 use gold in their business, and therefore, buying
14 futures are completely different in their position
15 from the speculators.

16 The speculators are long, and the
17 commercial hedgers are all short. That is not
18 very good ideas of how to predict. Am I going to
19 guess the speculators are right or the commercial
20 hedger is right.

21 MS. ELDER: What we don't know without
22 doing some more analysis is what impact --

23 UNIDENTIFIED SPEAKER: What I am
24 saying --

25 MS. ELDER: -- that has on price.

1 UNIDENTIFIED SPEAKER: -- it is an
2 excellent support for your position in a market
3 where that kind of data is more available.

4 MS. ELDER: I appreciate that. Sure.

5 UNIDENTIFIED SPEAKER: This is the kind
6 of statistical analysis I was suggesting you might
7 do on the short-run. If I gather the conclusion
8 is one of the issues is how good (inaudible), and
9 I think what you said was (inaudible).

10 MS. ELDER: I said that with respect to
11 second quarter at any rate.

12 UNIDENTIFIED SPEAKER: I think, in
13 general, I would almost characterize the longer
14 term models as being kind of falling a lot in that
15 kind of character. That is, if I could tell you
16 what the oil price is going to be, oil price path
17 is going to be, I could probably tell you within
18 an order of magnitude where the gas price is going
19 to be. There are a few other things that would
20 have to go in there. I am trying to get an idea
21 as to how good is our short-term forecasting. Is
22 it on the order of magnitude that where the macro
23 economists when they try to forecast when the next
24 recession is going to be, or do you think you are
25 actually closer to getting what the gas price is.

1 MS. ELDER: Given -- we have put ours on
2 the website, which means anybody can look at it,
3 which means that I am going to get judged by my
4 results.

5 UNIDENTIFIED SPEAKER: Again, it depends
6 on how you condition it. It depends on what you
7 assume about oil prices for example.

8 MS. ELDER: As one particular input.
9 One of the reasons why I go back and forth and I
10 get so much schizophrenic over, including oil
11 prices, is that I have statistically decent
12 results without including it, and I have this sort
13 of intellectual bias that I believe right or
14 wrong, I always have a tendency to believe that
15 gas and oil markets are (indiscernible) because
16 oil is a global market and gas, at least for the
17 moment, is still a North America market, you know,
18 blah, blah, blah, blah.

19 Then you saw what happened with rising
20 oil prices in the second quarter, and go okay, I
21 better go back and look at the model, and all
22 right, maybe I better add the oil variable and
23 what happens when I do that.

24 You have a much bigger impact, at least
25 in the specific model that I built, you have a

1 much bigger impact from assuming no LNG, or taking
2 10 or 15 percent off the demand forecast than you
3 get from oil. So, the oil had a bigger impact
4 than I would have wanted to believe it would have.

5 Let me put it that way, from an
6 investigatory perspective. It really had a bigger
7 impact than I wanted to believe it would have.

8 But still then, I get back into this debate about
9 if I put it in the model, then what do assume for
10 world oil prices, do you I use the OPEC target, do
11 I use the new rumored OPEC target, do I use EIA,
12 you know, what the heck do I use, and do I really
13 want to be in the business of forecasting world
14 oil prices, and I think I am not ready to go there
15 yet.

16 UNIDENTIFIED SPEAKER: I think that is
17 exactly the problem people on the longer term
18 projection have. They don't want to get into the
19 issue of having to forecast the oil prices, and
20 yet they keep coming back.

21 MS. ELDER: You keep coming back there,
22 yeah.

23 MR. TOMASHEFSKY: I have a question or
24 two actually. I think your basic theme is let's
25 make this as simple as possible. We don't have to

1 get into this rocket science exercise to develop a
2 short-term forecast.

3 Having said that, you make the comment
4 that technically forward the spot prices are
5 adjusted for risk, so if you get that risk
6 profile, are you suggesting that the use of
7 forwards with a risk factor associated represents
8 a good forecast?

9 MS. ELDER: I wouldn't quite go there
10 because I think you come back to that question of
11 whose risk measured when.

12 MR. TOMASHEFSKY: All right, assuming
13 you can figure out whose risk it is.

14 MS. ELDER: Then from a technical
15 mathematical perspective, that might be true, but
16 I would say I am not really ready to commit that I
17 would agree to use forwards instead of spot.

18 MR. TOMASHEFSKY: Okay, and I guess the
19 second question under this scenario, does the risk
20 ever become negative? If you look at the
21 estimate, does the futures price then represent a
22 forward to which we expect at any given point?

23 MS. ELDER: Are you thinking that it
24 would always be above spot? Is that what you mean
25 by positive and negative?

1 MR. TOMASHEFSKY: No, if it goes below,
2 then your net risk is going to be negative, at
3 least in the formula.

4 MS. ELDER: That's right, yeah. It
5 means that you would believe that risk is
6 declining over time instead of increasing.

7 MR. TOMASHEFSKY: We have had a tough
8 time defining what risk actually is. We have gone
9 back and forth about that, so it is possible under
10 that scenario that risk could actually be
11 negative?

12 MS. ELDER: I would agree, yeah. Risk
13 could decline over time instead of increase over
14 time.

15 MR. BRATHIWAITE: This morning, I think
16 Jariam asked Hill, I think it was Hill, about this
17 idea of taking the short-term futures prices and
18 taking it out to what is the long-term or long-
19 term projections, and he Hill said he didn't see a
20 problem with that. I think it was Hill, right?
21 You seem to have a different view. Could you just
22 clarify that position for us, please?

23 MS. ELDER: I guess by clarify, you mean
24 say a little bit more. I think what makes me
25 nervous about it is the fact that which forward

1 curve would you use, it changes every day. It is
2 less liquid over its course. If you were talking
3 about just maybe the prompt month, the next month,
4 I have a lot more comfort with using that
5 particular month's price in place of my forecast
6 or anybody else's forecast.

7 When you are talking about a longer
8 period of time, I think that is what would really
9 make me nervous.

10 MR. MAUL: You are recommending against
11 something we already did which is in our last
12 forecast --

13 MS. ELDER: You are not the only ones.

14 MR. MAUL: Oh, I know.

15 MS. ELDER: That is why I say I get
16 asked this all the time.

17 MR. MAUL: If we don't do that in the
18 future now, two years from now if I have a product
19 due two years from now and I have the time and the
20 resources to build in some different capability,
21 if I happen to provide a product six months from
22 now, what do you recommend we do if we don't do
23 the NYMEX short-term, what else can we put in the
24 short-term hole? How do we fill that gap?

25 MS. ELDER: One think you could do is

1 try to develop your own short-term modeling
2 capability very quickly.

3 MR. MAUL: I can't do it with the time I
4 have.

5 MS. ELDER: Then what I would do is I
6 would probably continue to put the forwards on
7 top, but I would put a lot of disclaimers around
8 it that recognize that this happens to be the
9 forward from this particular day, that the forward
10 curve will change depending on what day you look
11 at it, that it is less liquid over time, rather
12 than select a particular day and sort of have
13 people say, well, because that particular day is
14 the one you chose, that must be the right view of
15 the short-term market.

16 I think the thing that I can emphasize
17 enough is that because the forward market trades
18 every single day, its view of the future trades
19 every single day. What I don't have with me that
20 one of my colleagues was going to put together is
21 a movie we have of every day's future's curve for
22 like the last ten years. You just see the curve
23 just bop all up and down all over the place.

24 MR. MAUL: I've got slides of that. We
25 have developed the same thing you are showing and

1 how much it changes week by week.

2 MS. ELDER: Right, right. We've even --
3 let me give you one more example. The Wednesday
4 before Thanksgiving, the EIA issued its storage
5 report, and it had what appeared to be an error
6 claiming that 48bcf had been withdrawn, which
7 interestingly enough if you are familiar with or
8 done the analysis on it to be familiar with the
9 average amounts pulled from storage in any given
10 month over the course of the injection withdrawal
11 season, 48 bcf in the third week of November still
12 puts you well within normal.

13 It just so happened that November in the
14 rest of the country had been so warm, that the
15 previous' week's withdrawal was only 6bcf. So you
16 go one 6 bcf, the next week 46 bcf, the market
17 goes wacky and the prices rise and the futures
18 rise by a \$1.40 per mmbtu overnight in like all of
19 the next six months.

20 You go from maybe a 12-Month Strip of
21 kind of 6.60 number that I had in the chart back
22 here.

23 MR. GOPAL: And then (indiscernible)
24 actually made the correction and told them exactly
25 what it was, the price dropped by --

1 MS. ELDER: Exactly, exactly.

2 COMMISSIONER BOYD: You are dealing with
3 social behavior which is one of my favorite
4 topics.

5 PRESIDING MEMBER GEESMAN: Could you
6 control for that by averaging forward prices over
7 the last 30 days or over the last 90 days?

8 MS. ELDER: You could. That might be
9 one way of dealing with it, then I think you would
10 want to think about if you do that, you are
11 arguably leaving out information or information
12 about new trades as people gain new information,
13 that price changes.

14 I think you would want to understand a
15 little bit more about why day to day, the NYMEX
16 price changes before you quite went there, but it
17 is worth thinking about.

18 PRESIDING MEMBER GEESMAN: I guess the
19 concern I have, particularly at this short-term
20 end of the market I don't think we are looking for
21 the perfect answer, I think we are looking for the
22 least bad answer.

23 I don't think it works in a public
24 policy environment to say governor, I know the
25 market says "X", but we've got a really smart back

1 at the Commission that says "Y". You may serve
2 out the rest of your professional life in a small
3 condo in West Hollywood after the voters are done
4 with you. Believe our smart guy, government can't
5 work that way. We need a slightly more
6 transparent and arguably less bad way in which to
7 address at least those short-term price
8 projections.

9 I'm not certain there is a better way
10 than making some use of market indications. I
11 know not only did we do something like that in our
12 last cycle, the Public Utilities Commission in
13 trying to determine a market price reference
14 against which the renewable portfolio standards
15 bids would be evaluated, elected to rely on the
16 forwards market.

17 I think they are talking about going out
18 four or five years into the illiquidity period and
19 beyond that, I think they were averaging
20 escalation rates.

21 MR. MAUL: I think it's our forecast and
22 EIA's.

23 PRESIDING MEMBER GEESMAN: I don't think
24 we are looking for the holy grail as much as we
25 are looking for the least bad.

1 MR. MAUL: Transparency.

2 MR. BOYD: It is always the most safe.

3 MS. ELDER: It is always the most safe.

4 PRESIDING MEMBER GEESMAN: Welcome to
5 the government.

6 MR. MAUL: You have some questions back
7 here, yeah.

8 UNIDENTIFIED SPEAKER: (Inaudible.)

9 UNIDENTIFIED SPEAKER: Are there
10 experiences that you have had that give you a
11 sense of when it is appropriate to rely on
12 information you are getting from the oil market
13 and when it might be appropriate to consider those
14 modeling efforts and when it may be inappropriate
15 or unnecessary to consider them based on these
16 stories that you have written with some of the
17 models?

18 MS. ELDER: I would say that I don't
19 have a good sense of that yet. Let me put some
20 bounds around that. In a constant oil price
21 world, it doesn't matter much. We seem to be
22 transitioning from that kind of environment where
23 we can count on oil prices being between \$22 and
24 \$28 a barrel to \$40 and \$50 as we experienced this
25 year. That is what gets hard is to feel

1 comfortable that you have a good sense.

2 When you are in the natural gas market
3 expert, world oil prices and the impact of what
4 all the different forces that drive world oil
5 prices including potentially a falling dollar, so
6 that is a much bigger piece of was to try to
7 handle.

8 MR. MAUL: Luis.

9 MR. PANDO: I just want to make one
10 comment. I am a big believer too if you know me
11 in fundamental models, and I have used them a lot.
12 The reality is that the financial markets are
13 rating our companies on market, as companies were
14 allowed to take a certain amount of risk.

15 I believe that the market should be at a
16 certain point, but I can only deviate from the
17 market by a certain amount given Path 133 and
18 other accounting type conventions that will save
19 your risk now is \$150 million and I don't care
20 what you believe, and we are limited by that, and
21 we do have to consider the forward whether we
22 believe different or not. It is the reality of
23 the financial accounting.

24 To their defense, it is an honest way,
25 at least the most honest way of trying to keep

1 where your financial statements are.

2 I might say take out the money \$100
3 million, but that is just my opinion. The market
4 is saying you are out of the money. (Inaudible.)
5 I understand where you are coming from, but we are
6 living in what we can do with those.

7 MS. ELDER: I think as an independent
8 consultant, I get a little bit more leeway on
9 that. I've had discussions about these kinds of
10 issues with the rating agencies. In fact, I
11 worked on the \$13 billion bond offering from
12 California which actually did use my forecast, and
13 they got it.

14 What the key was to give them a good
15 story about the market, they got it, and they got
16 comfortable with it. I think there may be some
17 truth to the measurement because of who it comes
18 from.

19 MR. TOMASHEFSKY: How can we make use of
20 utility procurement information to kind of reduce
21 the amount of risks associated with that because
22 we know that a large portion of the procurement is
23 not based on spot prices? It is not based on
24 futures prices, but yet there is some contract.
25 Of course, a lot of it is tied to spot prices

1 anyway as far as what they pay.

2 How can we make use of the weight cog to
3 say soften the amount of volatility we would have
4 in a three-year forecast?

5 MS. ELDER: One thing -- I am answering
6 this off the top of my head, Scott, which is
7 probably unfortunate because it deserves more than
8 30 seconds of thought, never mind the fact that I
9 come out of PG & E's old gas purchasing department
10 that helped develop its own purchase policies and
11 is famous for things like \$1.81 Canadian gas for
12 several years at a time.

13 One thing conceivably that you can do is
14 develop a longer term sort of portfolio of price
15 (indiscernible) or supplies of different
16 (indiscernible) that have different expiration
17 dates so the prices expire at different dates.

18 Apply some price collars as a financial
19 derivative around some of those contracts for the
20 prices. Those sorts of tools may be worth taking
21 a bigger look at, a better look at.

22 MR. TOMASHEFSKY: Yeah, like you said,
23 it is more than a 30 second spot, but it allows
24 you at least to mute some of the I guess going
25 into an unknown world as far as just playing with

1 numbers as opposed to trying to understand
2 procurement activity and how that actually fits
3 because we always hear the argument, that while
4 even when prices go up to \$10, well, it is not
5 really the California consumer is paying because
6 there is a portfolio of gases behind that. So, it
7 may not be \$10, maybe it is \$7 on a spiking day.

8 MS. ELDER: On average basis, and there
9 is some gas that went into storage at whatever the
10 summer time, gas prices were, and there is a mix
11 of contracts. So, there is some truth to that,
12 and that is sort of what having that portfolio of
13 supplies does, is that it mutes the impact of the
14 price change on any given portion of the
15 portfolio.

16 MR. TOMASHEFSKY: Maybe it will be
17 useful as we look at some of the data that we are
18 exploring in terms of what we are collecting and
19 see what type of gas that is out there might be
20 able to help us along with that process.

21 MS. ELDER: What is interesting, I do
22 know that different state commissions have
23 addressed LDC gas cost to consumers in different
24 ways.

25 There are some states that want the

1 utilities to hedge and do a lot of hedging. There
2 are other states that don't want the utilities to
3 do any hedging at all. There are states that have
4 benchmark sort of procurement mechanisms where
5 they split the savings if there are any savings.

6 There are other states who feel that
7 those mechanisms are a license to write checks.
8 New Mexico will just not do that. Everybody has
9 sort of taken a different kind of take on it, but
10 one thing that is going on is that people are
11 beginning to relook at that issue.

12 We have gone away from the extraordinary
13 long-term contracts that were in place ten to
14 fifteen years ago to sort of converting to us.
15 Now people are beginning to say, you know what, in
16 this price environment relying on spot index
17 doesn't make a lot of sense.

18 MR. MAUL: Katy, thank you very much.
19 As you folks can all tell, this is an issue that
20 we're obviously very interested in, and we
21 appreciate the discussion, the round table that is
22 going on here, and we have one more speaker coming
23 up. After that, we would like to have more of a
24 panel discussion of just people's thoughts. I
25 know there are a lot of people in the audience who

1 don't have prepared remarks, but have some
2 thoughts and may feel passionate about various
3 issues we have already talked about or we haven't
4 yet talked about. We would appreciate your views
5 on those issues as well.

6 COMMISSIONER BOYD: I just want to say I
7 appreciated this last dialogue that just took
8 place. I very much find myself agreeing with
9 quite a bit of what you say, and I appreciate the
10 fact that you have stirred the pot for us.

11 MR. MAUL: Our next speaker is Herb
12 Emmrich from Southern California Gas Company, and
13 Herb has a presentation for us.

14 Herb, if I understand it correctly, you
15 submitted it in writing as well under Burney
16 Rosa's signature as well.

17 MR. EMMRICH: That's right. I do have
18 with me Scott Wilder, our business economist, and
19 Jeff Huang. If they could sit over here, I might
20 ask them to help me in this presentation.

21 Commissioners, I really appreciate the
22 opportunity for Southern California Gas Company to
23 participate in this workshop. We have had a very
24 good working relationship with Commission staff,
25 especially help on the LNG side to clarify what

1 the costs are. I know you are working actively on
2 the LNG, and we really appreciate that.

3 In our presentation, we try to actually
4 answer the questions that the staff asked, so we
5 would like to go through that.

6 What are the market characteristics to
7 be included in the short-term and long-term
8 modeling exercises? Of course there are core
9 customers and non-core customers. Core customers
10 are residential are driven to a large term related
11 to weather, and the long-term driven by population
12 growth, housing construction, energy efficiency
13 efforts.

14 Large commercial and industrial
15 customers are influenced by gas prices because
16 they are competing in the market place, and in
17 California we have had a very difficult time with
18 large industrial customers moving out of this
19 state because prices are too high on the energy
20 side.

21 On power generation, gas is on the
22 margin, and the cost of gas for power generation
23 determines in large part on how they can compete.
24 There is a regional market now, and if you don't
25 have the gas price, the power generation will be

1 out of state.

2 The long-term demand for gas and
3 electric power production of course is dependent
4 on the demand for electricity, energy efficiency,
5 state policies and so on.

6 Nationally, demand growth on the natural
7 gas side for power generation has really been
8 increasing. Most of the new plants are combined
9 cycle gas-fired plants, and that has increased gas
10 demand quite a bit.

11 We believe that modeling should include
12 alternate fuel prices, environmental externality,
13 and of course national policies on electric
14 production.

15 MR. MAUL: Herb, did I hear you
16 correctly say that you felt that high natural gas
17 prices in California have driven some of the
18 industrial customers out of California to other
19 states?

20 MR. EMMRICH: Absolutely. We've lost a
21 tremendous amount of industrial customers out of
22 our service territory, and I am sure it is the
23 same for PG & E. I believe PG & E is speaking
24 after me. It has come to a low grinding level,
25 and actually looking at out in the next ten to

1 fifteen years, we think it is going to stay at
2 that level and maybe increase slightly. We have
3 really lost most of it already. There is not much
4 more that we can lose.

5 MR. MAUL: Do you have any analysis or
6 studies that you can share with us that are
7 written up?

8 MR. EMMRICH: Sure, we can provide that
9 to you at any time. The number of customers that
10 we have lost.

11 MS. KHOSROWJAH: Could you provide that
12 to CPUC as well.

13 MR. EMMRICH: Yes.

14 MS. KHOSROWJAH: Thank you.

15 MR. MAUL: We have also heard about the
16 demand structure issue which is a key modeling
17 input for us, but we haven't seen the actual
18 statistics for California. We are looking at the
19 nation, but not California specifically.

20 MR. EMMRICH: We can give you that for
21 our service territory and for the San Diego Gas
22 and Electric service territory.

23 MR. MAUL: Thank you.

24 MR. EMMRICH: What are the major issued
25 to be addressed in modeling the infrastructure,

1 supply, and price trends?

2 One of the big issues of course is LNG.

3 There are about 40 projects in the United States
4 to import LNG. There are three here in California
5 that I know of, one in Long Beach and two in
6 Oxnard, and a couple of them in Baja, California
7 that could also provide gas to California.

8 That has to be considered how many of
9 those projects will actually happen. We don't
10 know. We think there will be at least one on the
11 west coast, but there could be several of them in
12 the Gulf Coast and on the east coast of the United
13 States.

14 Since we have a market that is tied
15 together nationally, wherever that LNG comes in,
16 it is going to affect the price, and we believe
17 that will have a lid on prices in the long-term.
18 The gas prices will decline.

19 PRESIDING MEMBER GEESMAN: Do you think
20 there will be more than one or could be more than
21 one on the west coast?

22 MR. EMMRICH: We believe there could be
23 as many as three or four, but we think at least
24 one. Maybe whoever is first wins, but certainly
25 the prices are there to justify having more than

1 one.

2 Electricity markets to long-term it is
3 dependent on transmission constraints. I am
4 talking about demand in our service territory, how
5 much electricity can be generated within our
6 service territory.

7 There is also a lot of talk about
8 distributed generation that if smaller power
9 plants are located on customer sites, that will
10 change the need for transmission lines and so on.

11 The governor's photovoltaic proposal is
12 one that is basically like distributed generation,
13 and we are supporting that kind of an approach.
14 Of course, the proposal for renewables, which we
15 are actively engaged in and we strongly support
16 renewables.

17 The goal of 20 percent renewables, and
18 we are well on our way to meet that in our sister
19 utility San Diego Gas and Electric.

20 How should a base case or a reference
21 case be used in the market analysis?

22 We think a base case should reflect the
23 key current characteristics of gas and electricity
24 market in California. Hopefully, we can agree on
25 some assumptions that are non-controversial. Way

1 back in the past, there was so much controversy,
2 that we couldn't even agree on the time of day,
3 and I think we are past that, that everybody is
4 pulling together and trying to solve the problems
5 instead of creating problems for each other.

6 What should be included. I think a
7 plant in Baja, which is already in process or
8 other plants that the state believes will be come
9 on line and should be considered.

10 Of course, the CPUC-mandated energy
11 efficiency investments which we are required to
12 meet now based on the decision that was issued
13 just a couple of months ago. We are committed to
14 meeting the energy efficiency targets for both gas
15 and electricity, and that should be reflected in
16 your forecast.

17 MR. MAUL: Herb, you mention on your
18 reference case here that we should include the
19 current characteristics, the non-controversial
20 ones. How do you treat oil?

21 MR. EMMRICH: We can talk a little bit
22 later on the pricing aspects and so on, especially
23 what Katy said. I believe a lot in what she said.
24 I disagree with some of it and would like to
25 clarify that.

1 Of course there is the world oil market
2 and most of the supply of energy in the world
3 comes from oil. It is shipped all over the place,
4 and that puts a lid on prices. OPEC still has
5 plenty of oil to produce, and if they wanted to,
6 they could drive the price down to \$20 a barrel.
7 They would have to make the investments in
8 infrastructure to do that, but they are capable of
9 doing that.

10 That always has to be considered, and
11 that is a personal view. You have to adopt some
12 kind of view. I can't tell you what that view
13 ought to be. There are plenty of agencies that
14 forecast oil prices. There are many forecasts as
15 there are forecasters.

16 Oil is to a large part, politically set.
17 It is not driven by the basic supply and demand
18 forces out there. There is still a large
19 political component of that, and you have to take
20 that into account.

21 On our forecast thing, I think what is
22 probably most important is to look at the
23 sensitivity of the forecast. A forecast is just
24 one spot estimate out in time, but we know that
25 every forecast will be wrong. What you do know is

1 that around that forecast, you have certain
2 variation. You have certain risk around that
3 forecast.

4 In the shorter term, that risk is much
5 greater than the longer term because supply and
6 demand are now in balance, so anytime you have any
7 kind of disruption, either on the supply side or
8 the demand side, you know, a cold front coming
9 from Canada is going to increase price prices by
10 60, 70, 80 percent without a problem because you
11 don't have any access capacity coming on line
12 right now. So, you just have to take that into
13 account and deal with that.

14 The price sensitivity should be taken in
15 account going out and doing one forecast doesn't
16 really serve a good purpose. You have to have a
17 high and a low based on whatever confidence you
18 want. We look at a 95 percent confidence for our
19 forecast because if you are making an investment,
20 you have to take that into account. What is the
21 variability of your energy costs.

22 Should the market forecast be a
23 fundamental forecast or based on futures prices,
24 what is the relationship between projections, spot
25 prices, and prices projected by modeling

1 exercises?

2 For long-term forecast, I think modeling
3 on a national level is necessary, and you should
4 have a fundamental forecast.

5 The spot forecast gives you the best
6 possible market opinion on the future price right
7 now, and you know it is going to change tomorrow
8 because there is new information tomorrow.

9 The day after that, there is other
10 information, and the price can go up and down. It
11 is going to gyrate, but that price today is the
12 best information available in the world. There is
13 no better information because everybody is putting
14 their money down.

15 You can't do better than that. If you
16 try to outguess, you know, if I could outguess it
17 for one day, I would be the richest person in the
18 world, and I wouldn't be here. I'd be out there
19 making money. So, you can't do that, you have to
20 accept the fact that prices will change each and
21 every day and they are going to be very volatile
22 each and every day because supply and demand is in
23 balance. There is no overhang of supply like we
24 did five or six years ago where we had the gas
25 bubble. We could absorb a lot of that increase in

1 demand just be bringing the supply on line. The
2 capacity was there, it is not there now.

3 That is the same thing on oil prices
4 right now. OPEC has not increased the
5 infrastructure to have an overhang of three or
6 four million barrels a day of excess capacity.
7 Supply and demand are unbalanced, and they will
8 make those investments in my opinion to create
9 that balance out in time.

10 We have stopped doing long-term
11 forecasts ourselves. What we are doing is saying
12 sort of a basket approach of looking at CERA,
13 PIRA, EIA, the CEC, whoever is out there looking
14 at the forecasts. The reason for that is when we
15 did our forecasts, we were always in that range
16 anyway, and we don't have any better information
17 than the experts that spend all of their time
18 doing that.

19 Katy has a forecast, I'll use hers too.
20 The people that are spending all their time in
21 this effort are the experts, and there is no
22 reason why you shouldn't do that, use that
23 expertise, do some kind of weighting of those
24 forecasts, and I think you will be okay, you are
25 going to be in the range.

1 In the short-term --

2 MR. MAUL: Herb, do you weight ours 90
3 percent and everybody else's 2 percent each or --

4 MR. EMMRICH: We tend to do like an
5 equal weighting.

6 PRESIDING MEMBER GEESMAN: Let me ask
7 you in your business, what is the longest time
8 horizon you find it productive to look at in these
9 forecasts?

10 MR. EMMRICH: We look at a 20 year
11 forecast as part of the California gas support.
12 The reason is a lot of the investments we make,
13 pipelines are going to last 30 or 40 years. If
14 somebody is going to build a factory in
15 California, that factory is going to be operating
16 for 20 to 30 years. They want to have some kind
17 of idea of what their cost of energy is going to
18 be, both in the gas and the electric side. So, it
19 is reasonable.

20 If he is building that plant in his
21 mind, he has already got a forecast of his costs.
22 We can add to that information, it is very much
23 helpful to the investor.

24 PRESIDING MEMBER GEESMAN: Do you go out
25 with anything that you make public beyond 20

1 years?

2 MR. EMMRICH: Actually, we don't really
3 make public our forecasts on the Cal Gas Report
4 anymore, it is part of the work papers which are
5 available to the staff. The reason for that is we
6 don't want to get sued.

7 PRESIDING MEMBER GEESMAN: Sure.

8 MR. EMMRICH: They are saying the gas
9 company who is the biggest gas company in the
10 United States and must have all these smarts can
11 actually forecast gas prices, but we know that is
12 not true.

13 The market will determine what the
14 forecast is and where the reality is, and I cannot
15 tell you that I know better than other people. I
16 have my own fundamental beliefs based on 20 years
17 of history, but there are a lot of other people
18 that spend even more time than I do, even though I
19 am in the business every day.

20 On the short-term, again, I think the
21 market provides you the best information. There
22 really is no better information. Everybody is
23 putting their money down and saying, the next two
24 or three years, this is what I think the futures
25 price is going to be.

1 As you go out in time, there is less and
2 less liquidity out there, and some years out in
3 time there is really no contract available at all.
4 There is nothing being traded. I think that is a
5 pretty good approach in the two year time frame.
6 As you get out and stick to your fundamental
7 forecast or do this basket approach for forecast.
8 If your staff thinks they can do a better forecast
9 than PIRA or CERA or EIA, welcome to it, but I
10 don't think you are going to do better than them.
11 You are probably not going to do worse, but you
12 are going to be in the ball park.

13 MR. BRIDGES: Herb, just on the question
14 of CERA and PIRA forecasts, particularly the CERA
15 ones, they use the scenario approach. So, they
16 say if this happens, then we have this price
17 forecast. If this happens, then we have a
18 different price forecast. How would you
19 incorporate that when there are multiple
20 forecasts, scenario-based forecasts? You don't
21 really have a base case.

22 MR. EMMRICH: If you do a forecast, you
23 are always doing a scenario forecast. There is no
24 such thing as a non-scenario forecast because I
25 have to have assumptions on economic growth, on

1 inflation, on oil production, LNG coming on board.
2 You are always doing that. We take the base
3 forecast.

4 MR. BRIDGES: I am saying they don't
5 have a base line.

6 MR. EMMRICH: If they don't have a base
7 one, we just take the two that we like and average
8 them.

9 We try to get in the realm of reason,
10 try to get into the realm of reason. If you look
11 at enough long-term forecasts, you see that they
12 tend to converge, and they are not that different.
13 You are going to be okay.

14 Even if you have a thousand people
15 giving you the forecast and you take the average,
16 when you go 20 years out, the price is going to be
17 different. You know that because that is just the
18 reality of it.

19 Like I said, I think long-term forecasts
20 should be based on market fundamentals on a
21 national level, even internationally because of
22 oil. Oil is the largest supply of energy in the
23 world.

24 With LNG developing very rapidly, LNG is
25 also going to become one of the largest supplies

1 of energy in the world because it is fungible, it
2 is moving around. It will be sold to the highest
3 bidder, and it will have an impact.

4 Futures. We already said they are very
5 good I think in the short-term, not that good in
6 the longer-term as you get out there because there
7 are not enough trades out there to get a good feel
8 for it.

9 If you look at futures right now in the
10 years 2007 and 2008, when LNG is scheduled to come
11 on line, you see a dip in the futures price. So
12 the market consensus right now is LNG is going to
13 arrive, it is going to have a significant impact,
14 and it is going to put a lid on price increases.

15 We believe that long-term prices will be
16 going down. Within each year, the spikes are
17 going to belie this, they are going to be up and
18 down quite a bit. That is not as relevant as the
19 long-term price forecast if I am an investor
20 because I can hedge away from that risk. I can
21 take a futures position and hedge away from that
22 risk.

23 This is a little bit history in forecast
24 looks in our world, and of course, 2001 was a
25 disaster for everyone in California, but also

1 nationally. On some days prices were \$60 a mcf
2 here in the California border, and that was
3 because of extraordinary demand for gas for power
4 generation. There was no hydro in the Pacific
5 Northwest and all the California producer was
6 shipping power north. It was a tremendous impact,
7 and there was no power coming south because there
8 was none available from hydro.

9 If you go out in the future, we look at
10 prices being very stable around \$5, you do have
11 the summer/winter price differential which makes
12 sense. Price is low in the summer, it is a K
13 market, it is telling you to go store gas because
14 in the winter time it is going to be higher price.

15 It is basically giving you the carrying
16 cost of storage and the financial carrying cost of
17 putting the gas in storage.

18 Look at the upper and the lower limit.
19 Prices are going to gyrate in between that, and
20 you have got to expect that. There is a lot of
21 volatility that we see based on the history that
22 we have over the last ten years.

23 If you go further out in time, the price
24 is less. That is what it is, that gyration is
25 risk. I believe, Commissioner, you were a bond

1 trader, so you know more about risk than I will
2 every know.

3 PRESIDING MEMBER GEESMAN: That is why I
4 retired.

5 MR. EMMRICH: This forecast was used in
6 long-term resource plan. We are comfortable with
7 our forecast even though it was based on \$28 oil
8 price at that time, and prices have gone to \$50
9 and are back around \$40 now.

10 If OPEC keeps producing the price is
11 going to go down, but who knows what they are
12 going to do.

13 I was going to turn it over to Scott
14 Wilder to talk about what we do on the demand
15 projections if that is okay.

16 MR. WILDER: Thanks, Herb. What are the
17 issues that need to be considered here, and that
18 essentially means making assumptions, whether we
19 decided to include something or not. That is an
20 assumption. The kinds of things that we do look
21 at and would include in the forecast are things
22 like weather, both heating degree days and cooling
23 degree days (inaudible), and then the outside
24 factors, like population growth, new housing, job
25 growth. Some of that feeds into our growth in

1 customers, which in turn drive the residential
2 demand forecast.

3 Also fuel prices, not only gas prices,
4 but also the electric prices as well for EG as
5 well as some substitute prices nationally, things
6 like coal prices, oil prices.

7 Longer-term we also have to take into
8 account things like renewables mandates, demand
9 reduction goals with energy efficiency because
10 energy efficiency impacts not only our direct gas
11 demand, but it will also impact on the electric
12 side our gas demand for electric generation in a
13 sense. That tends to be gas fired EG tends to be
14 the electricity production on margin that is
15 almost one for one affected by either renewables
16 reduction of electricity or by energy efficiency
17 gains in electricity.

18 We also need to take into account any
19 changes, expected changes in the future forecast
20 period for air quality restrictions, what kinds of
21 substitute fuel may or may not be burned in parts
22 of our service area.

23 Finally, even longer term US and state
24 potential carbon dioxide restrictions are probably
25 pretty premature to speculate right now on what

1 those kinds of policies might be, but 20 years
2 out, there may be some things that we want to at
3 least be keeping in the back of our mind.

4 MR. BRATHIWAITE: Could you just expand
5 on numbers one, two, three, the third bullet about
6 the immigration policies?

7 MR. WILDER: I'm sorry, I forgot to
8 mention that. That is actually one of the more
9 important long-term drivers of population.

10 Right now, if California's population
11 growth is roughly twice the rate of the United
12 States and in a typical year anywhere from a third
13 of a half of our state's growth rate comes from
14 foreign immigration.

15 If the United States immigration policy
16 were to change, most directly say if there were to
17 be numerical restrictions, that could obviously
18 reduce California's population growth. A little
19 more subtly, if US immigration policy were to
20 change in a way to be more in line with some other
21 popular countries for immigrants, there is Canada,
22 Australia, and New Zealand, currently our policy
23 nationally has been ever since the mid 1960's one
24 of family reunification.

25 The result of that is that immigrants

1 coming here tend to congregate where their
2 relatives already are, which means that parts of
3 the nation, California being the largest part
4 getting about a quarter of the new immigrants in
5 the entire United States each year, we tend to be
6 one of the areas where immigrants already are, and
7 where the relatives are coming in on family
8 reunification visas tend to come to. It kind of
9 feeds on its own growth.

10 With the current policy, we being a high
11 immigrant area, we continue to get more new
12 immigrants who are relatives of ones that are
13 already here.

14 If US policy were to change or to a
15 point based system based on things like skills and
16 education, that could significantly reduce
17 California's population growth. In that case, the
18 immigrants would tend to come and disperse more
19 evenly across the United States in a pattern more
20 consistent with local economic growth patterns and
21 job opportunities instead of getting a quarter or
22 more of all immigrants into the country,
23 California would probably tend to receive more
24 along the lines of 12 percent or so, which is
25 roughly our economic portion of the country.

1 MR. BRATHIWAITE: We like immigrants
2 because they use a lot of gas.

3 PRESIDING MEMBER GEESMAN: The State
4 Department of Finance population projections
5 attributes most of California's long-term
6 population growth going forward to fertility
7 factors and in-state births. Can I infer that you
8 don't feel that those projections don't adequately
9 capture the influence of immigration policy?

10 MR. WILDER: I believe they do. the
11 population projections that we just, we look at
12 the Department of Finance projections. We also
13 look at vendor global insight on the nation's
14 largest forecasters, their population projections
15 both for US and for our Southern California
16 service area.

17 When I said our population growth rate
18 is much higher thanks to immigration, the majority
19 of California's growth rate is still due to
20 natural increase. There is a little bit of plus
21 or minor factor due to migration to or from other
22 parts of the United States, but the main reason
23 why we are growing faster than relative to the
24 rest of the country continues to be foreign
25 immigration.

1 Foreign immigration were to disappear,
2 for instance, the latest estimates for 2003 or so
3 is the population in California is growing around
4 1.7 percent a year. That is nearly double the
5 slightly under one percent a year from the country
6 as a whole.

7 If we were to say suddenly to lose the
8 additional foreign immigration compared to the
9 rest of the country, our growth rate would drop
10 not quite to what the US is, but to barely high,
11 it would be 1 or 1.1 percent rather than --

12 PRESIDING MEMBER GEESMAN: An
13 immigration policy driven scenario because of its
14 impact on population growth, which is a driver, we
15 found both on the natural gas side and on the
16 electricity demand side, might be a scenario that
17 we ought to take a look at.

18 MR. WILDER: I think so. It could have
19 a significant impact on growth and energy demand
20 of the state.

21 MR. BRATHIWAITE: If I might add a small
22 point here. I mean the view of the fertility rate
23 was what you are saying may not be inconsistent
24 because I think there are studies that have shown
25 that at least that early immigrants do have higher

1 fertility rates than the later generations of
2 people who are the national average I should say.
3 Your two views may not be inconsistent.

4 MR. WILDER: I think that is why even if
5 hypothetically if immigration here were to
6 (inaudible) than the rest of the country, why for
7 at least a few years, a number of years down the
8 road, we would continue to have a slightly higher
9 growth rate than the rest of the country, but with
10 the emphasis on (inaudible).

11 MR. MAUL: Scott, are the energy use
12 patterns different for immigrants versus natives
13 or are they the same, or does it matter, just
14 total population numbers, or the quality of the
15 population.

16 MR. WILDER: On a per capita basis, they
17 are not really that much different. Immigrant
18 households tend to be a bit larger, so per
19 household basis, that is like per residential
20 customer basis, they tend to be a little bit
21 larger.

22 MR. EMMRICH: We just have a slide here
23 on heating degree days. This is why in the short-
24 term the residential small commercial industrial
25 market gas demand is tied to space heating load.

1 If there is cold weather, then you are going to
2 have a tremendous increase in gas demand. If
3 turns out to be warm, you are going to gyrate
4 down, so the market will reflect that.

5 If there is a cold wave coming down from
6 Canada like you did like 15 years ago, the Arctic
7 Express, we are going to send out a 5 bcf of gas
8 in Southern California, that is going to put
9 stress on the market.

10 MR. MAUL: Herb, do you recall what the
11 temperature is in LA is for that cold year?

12 MR. EMMRICH: We had colder than cold
13 during '91. In other words, cold is one in 35
14 years. It was colder than the one in 35 during
15 that cycle. So, we had that and no hydro and
16 everything added on top of that which created the
17 problem that we had.

18 MR. MAUL: Our chairman keeps telling us
19 a story about scenes -- I don't know if saw snow
20 or saw a picture of snow.

21 MR. TOMASHEFSKY: Snow in Pasadena.

22 MR. MAUL: Yeah, saw a picture of snow
23 in Alta Pasadena just on the outskirts of LA. If
24 you were to have that situation again, how far
25 above that heating degree if it turns up?

1 MR. EMMRICH: What I am showing you is
2 the yearly 1 and 35. In any one month, you would
3 have a very very big spike. The 1 in 35 peak day
4 is assuming an average temperature in LA of 38
5 degrees. If you can imagine that. It is beyond
6 my comprehension. I've lived there for 30 years,
7 so it would be extreme. It would be over 5 bcf
8 send out during that day.

9 COMMISSIONER BOYD: What role did -- I
10 keep hearing storage that during that bad year,
11 storage was extremely low, that we didn't put as
12 much gas in storage. You have not mentioned that
13 at all. Is that factored in?

14 MR. EMMRICH: Yeah, storage was low
15 because the generators were using all of their
16 power during the summer and they did not replenish
17 their storage. They went into the winter with 6
18 bcf where normally they would have had maybe 25 to
19 30 bcf of gas in storage.

20 The reason for that is because you had a
21 backwardated market that summer prices were
22 actually futures based prices in December and
23 January were lower than in July. So, it was not
24 what we call a carry market. In other words, if
25 you bought gas for storage, everybody was saying

1 and the market was saying you are wasting your
2 money because in the future you can buy it at a
3 cheaper rate. Nobody expected extremely weather
4 and no hydro coming on line at all in the Pacific
5 Northwest, it just didn't rain. So, they had
6 minimal run of river and so on. It is a
7 combination of many many different factors.

8 Scott, if you want to describe this.
9 This is employment drives, of course, the
10 commercial industrial market. It is population
11 that drives the residential market.

12 MR. WILDER: Yeah, we talked a lot about
13 population household growth, so this graph should
14 make it fairly obvious that employment job growth
15 is even more volatile. We have just come through
16 what is historically a relatively mild slow down,
17 at least for Southern California in the economy.

18 You can see what has happened to job
19 growth. We suddenly went from almost 3 percent
20 down to a little bit negative in 2002 and are
21 beginning to recover the last couple of years.

22 Job growth is our proxy in our sub-state
23 area economic activity driving commercial and
24 industrial, mainly commercial.

25 The customer growth. About 96 percent

1 of our customers are residential. In terms of new
2 growth, it is even more than that. As Herb
3 mentioned, our commercial customer growth is slow,
4 and our industrial customer growth, even in the
5 forecast is almost non-existent.

6 As far as customer growth goes, it is
7 mostly residential and we are forecasting around
8 1.4 percent or so, that is a driver for the
9 residential demand forecast, demand for household
10 or demand for customers forecasted separately and
11 then multiplied for our forecast customers.

12 MR. EMMRICH: As you can see, one
13 percent customer growth because we have such a
14 large base. That is a huge amount of additional
15 customers. We are hooking up about 80,000 new
16 customers a year.

17 MR. WILDER: Yeah, we have over 5
18 million customers currently and just about 5
19 million exactly are residential customers. So,
20 when we say 1.4 percent, we are talking in the 70
21 to 80,000 range.

22 MR. EMMRICH: Again, this is electric
23 generation gas demand. This is in our service
24 territory, and you can see in 2001 there was a
25 tremendous increase for the demand for gas for

1 power generation, and especially in the winter
2 time, which is basically never existing because in
3 the winter time, there is plenty of hydro
4 available.

5 Jeff, why don't you talk a little bit
6 about the wet and dry hydro in the future, what
7 the assumptions are.

8 MR. HUANG: Okay. This forecast is from
9 our most recent California Gas Report. The
10 forecast has represented a set of assumption, best
11 available assumption at that time. We actually
12 incorporate a lot of Energy Commission assumption
13 with regard to the hydro assumptions as well as we
14 incorporate Energy Commission's aggressive DSM,
15 electric demand assumptions.

16 As a result, it shows a reduction in eg
17 for the forecast. I believe the Energy Commission
18 for the dry hydro condition, they use the 1 in 10
19 dry hydro condition if I am correct.

20 MR. EMMRICH: During this spike period,
21 I think it was like 1 in 30 year low hydro?

22 MR. HUANG: Right. Again, that time was
23 in the crisis, and it was at the same time it was
24 also a dry year, and so most of our in base
25 generation were running pretty much all the time

1 to meet the demand.

2 MR. EMMRICH: To go on, what is the
3 desired way to approach demand assumptions? We
4 recommend developing standard economic models to
5 drive the non-policy portion of your demand
6 forecast. Of course, policy is always part of the
7 mix and you have to super impose some policy
8 conditions on top of that whether it is mandates
9 for energy efficiency or mandates for renewables
10 and so on.

11 There was some talk about elasticities.
12 Of course in the long-term, the demand is much
13 elastic than it is in the short-term. The short-
14 term technology is fixed, the infrastructure is
15 fixed, and in the long term everything is
16 changeable. The adjustments based on price will
17 reflect that out in time.

18 When our customers change our equipment,
19 when the equipment gets old, they will change it
20 out. If the price goes up, they will change it
21 out earlier until waiting the full life of 20
22 years, maybe they change it out after 18 years, or
23 we provide them incentives out of the Energy
24 Efficiency Program to change out the equipment
25 early by giving them maybe a 20 percent subsidy in

1 order to change out to reduce consumption.

2 The Energy Efficiency Program is
3 increasing tremendously on the SoCal Gas side. We
4 are mandated to spend \$100 million a year in year
5 10 of the forecast, so it is getting momentum.

6 Of course, the air quality restrictions
7 are another thing that are a concern where as in
8 other states, they are switching between oil and
9 gas. There is no such thing. You can't get a
10 permit. Air Quality Management District to burn
11 oil. You have to burn gas. It is good for the
12 gas company, but for the economy if oil prices
13 were to go below gas prices, they could not switch
14 if they wanted to.

15 During the crisis period, that was also
16 one of the problems that the power companies could
17 not switch over to oil. They had to use gas, so
18 everybody was chasing gas and just wasn't that
19 much available.

20 Is there any modeling that we should not
21 include in the above list? We like scenarios.
22 You should run several scenarios and do some kind
23 of waiting. Include all of the supply sources
24 that could come on line. There is heave activity
25 in Canada, there is heavy activity in the Rocky

1 Mountains, and then of course LNG.

2 If you are going to use NARG, and we
3 believe NARG is a very good tool, we have good
4 confidence in NARG, but it is again, the
5 assumptions you put in there on pipeline
6 capacities and what the oil prices are going to be
7 in order to give the incentive to drill, you
8 cannot predetermine. You have to do scenarios in
9 order to get a handle around that, how much impact
10 is there.

11 There was a question on air emissions.
12 Air emissions should play a role in forecasting.
13 If they keep tightening up right now, we are
14 looking at maybe losing our water generation
15 market in the San Joaquin Valley. There used to
16 be an exemption for agricultural, and because the
17 state does not meet its air quality goals, they
18 are clamping down on that, and we are probably
19 going to lose that market, we will go all
20 electric.

21 I don't know how that helps the state.
22 You are exporting pollution, but I guess if you
23 are in a local situation, you have that problem,
24 and you try to meet it the best you can.

25 We spent a lot of money to put the

1 farmers on gas in order to reduce emissions
2 because before that, they were running diesel, but
3 now gas is not even possible. It is probably
4 going to go to electric power generation to motors
5 instead of the small engines that we have.

6 The other thing is I think long-term is
7 we need to make some kind of scenario at least on
8 CO2 emissions because from what I see there is
9 slow movement for the US to start accepting the
10 reality of global warming.

11 Certainly in Europe, they have totally
12 bought into it, and they have been doing things
13 about it, and that will have an impact on power
14 generation.

15 Jeff, I would like to turn it over to
16 you on the electric sector, how should the natural
17 gas analysis be integrated with other energy
18 sector analysis?

19 MR. HUANG: For any long-term gas
20 forecast, I would recommend tying the demand to
21 the electric generation to electric supply and
22 demand.

23 From our point of view, the assumption
24 drives the end result. For example, a change in
25 electric transmission upgrade assumptions what

1 drives the in through for Southern California
2 market by having for example by having a PV-2
3 transmission it will reduce our through by "X"
4 amount because we are able to import out of the
5 state electricity into Southern California.

6 When the Energy Commission looks at the
7 long-term model, one of the things that the staff
8 should look at is a different transmission upgrade
9 option and scenarios as well a different hydro
10 sensitivity that is in the long-term price
11 forecast.

12 For the electric point of view, a lot of
13 things impacts it. There is various electric
14 demand scenarios depending on what your
15 assumptions are. I would recommend looking at
16 different gas demand by playing around with
17 different electricity transmission scenarios as
18 well as different resource scenarios.

19 MR. EMMRICH: The last item, a small
20 item, on the NGV's, we have heavily promoted the
21 NGV market, and that has legs. All the buses in
22 Southern California are using NGV's and it has
23 become a fairly good market, about 7 bcf a year,
24 so it has been very successful.

25 That may be counter active by having

1 other alternate fuels and also these hybrid
2 vehicles may reduce that, even though Honda is
3 pushing very heavily to have more NGV's for small
4 vehicles where we were targeting the bus fleet
5 market because you need compressors in order to
6 get that in the canisters, and you need large
7 volumes to make it cost effective, but that could
8 have an impact.

9 MR. MAUL: Herb, do you have any views
10 on if the hydrogen economy and the vehicle economy
11 will actually become reality? If so, would
12 natural gas be the transmission fuel or would it
13 be something different?

14 MR. EMMRICH: We actually are
15 participating in a task force on that, and you
16 know, it is very very expensive. There is
17 potential if they have technological
18 breakthroughs, but right now, to create hydrogen
19 from natural gas is a very expensive process.

20 If there is some other way to do it,
21 there is a lot of theory out there that there are
22 other ways to transform it, then maybe it could be
23 a reality, but you are looking at 10, 15, 20 years
24 out in my opinion.

25 PRESIDING MEMBER GEESMAN: In terms of

1 natural gas vehicles, if busses in Southern
2 California constitute 7 bcf, what sort of
3 potential exists in other fleets that might adopt
4 natural gas as a primary fuel?

5 MR. EMMRICH: Right now, we pretty much
6 have all the bus fleets, and there are things like
7 trash trucks and that sort of thing. There are
8 probably another 200 fleets out there and that
9 will maybe double the demand.

10 PRESIDING MEMBER GEESMAN: Okay, thank
11 you.

12 MR. GOPAL: You track historical NGV gas
13 consumption and future projections?

14 MR. EMMRICH: Oh yes, it is a separate
15 market for us. You are looking at Cal Gas Report?

16 MR. GOPAL: Yes.

17 MR. EMMRICH: It will show under the
18 core, it is a core market right now --

19 MS. KHOSROWJAH: 7 bcf per year?

20 MR. EMMRICH: Yes.

21 MS. KHOSROWJAH: Just for the --

22 MR. EMMRICH: NGV's yeah. Yeah, it is
23 growing into a big market. We spent a lot of
24 effort on that.

25 MS. KHOSROWJAH: Per day or just -- oh,

1 the total.

2 MR. EMMRICH: Oh, per year, no, not per
3 day. Boy, --

4 PRESIDING MEMBER GEESMAN: I think the
5 South Coast Air Quality Management District would
6 like to see you harvest that full 14 if that is
7 the --

8 MR. EMMRICH: 7 a day would probably be
9 a good number of all the cars were using NGV's and
10 I would look forward to that, it would be great.

11 If the Commission does not rely on
12 internal forecast, which other forecast should
13 they rely on? We already said what we are using,
14 CERA, PIRA, and EIA, those are good sources, and I
15 think if you look at all these forecasts and
16 weight them, I think you are going to be okay. I
17 don't think you can do better than that, and that
18 is acceptable. It has worked for us.

19 On the demand side, you can use the
20 California Gas Report. That is the best available
21 information from the utilities, and I don't think
22 you can go too long with that. I try to do a good
23 job. I don't know if PG & E does a good job, I
24 know that. So, I think you have got 99 percent
25 covered with that.

1 That is all I have.

2 MR. GOPAL: The average (inaudible) and
3 then you have every fundamental aspect plus
4 (inaudible).

5 MR. EMMRICH: Yeah, right. That's
6 right.

7 PRESIDING MEMBER GEESMAN: We did that,
8 Jariam, with oil in 1982. The Commission ended up
9 adopting a forecast that I think crested above
10 \$100 per barrel at some point in either the late
11 '90's or 2000, in 1982 dollars. Much of the QF
12 policy was adopted by the Public Utilities
13 Commission was premised on that forecast.

14 MR. EMMRICH: I think that is a good
15 example why you need a range of forecasts. That
16 probably was the ultimate high that everybody was
17 tuning into like the NYMEX is at \$10, if you think
18 that is going to be the price in the future
19 forever, that is not how it works.

20 We are dealing with commodities and
21 commodities go in cycles. If the price is high
22 everybody overinvests, they start dealing like
23 crazy and they drive the price back down. So,
24 just like this cycle, we are on a high now, and we
25 are going to go now. So, we think it is a lot

1 better to use a range when you are going into
2 forecasting.

3 MR. MAUL: Commissioners, more
4 questions?

5 UNIDENTIFIED SPEAKER: I would just like
6 to make one comment on this averaging concept. I
7 really object to it, and I just want to go on the
8 record, that I don't think you are going to get
9 much out of that. The reason I say that is the
10 numbers are not in my mind as important as the
11 story that you are telling.

12 If you are averaging scenario A that has
13 completely different assumptions with scenario B,
14 I don't know what you got. You've got kind of
15 mixed pie kind of thing related to the comment
16 that John brought up. You bring up this scenario
17 that doesn't make any sense.

18 So, I think the Commission has to sit
19 back and ask themselves why are we doing this. If
20 you are not trying to develop a Commission story
21 about how you think gas markets are working, and
22 you are trying to forecast, then you definitely
23 should get rid of the model because I don't think
24 that's going to do it.

25 On the other hand, if you really want to

1 have the capability to address some policy
2 questions under different kinds of conditions, you
3 need not an average projections done by CERA and
4 everybody else, you need your own capability. You
5 have to have enough trust in these people to go
6 ahead and say we will get the best information
7 around, but in the end, it will be a California
8 Energy Commission story. I will just shut up with
9 that, but I did want to get that.

10 MR. BRATHIWAITE: Let me ask you a
11 question, then, now that you have said that, and I
12 totally agree with you, okay. I tell you I agree
13 with you, however, going back to this morning when
14 Jarlam asked you about using the short term and
15 then going into long term, is that your view was
16 that was not too bad a method to do that.

17 Is your present view consistent with
18 that answer this morning?

19 UNIDENTIFIED SPEAKER: My present view,
20 the comment that I was asking is I think he raised
21 the question, we've got the stuff, can we go ahead
22 and do it. Why not? From everything I have heard
23 today, even though I think Katy makes some good
24 arguments contrary that technically if you want to
25 make money in the market, you might want to go

1 with her approach. If you want to convince a
2 number of other people outside who don't
3 understand all this stuff, you may be better off
4 doing it. I don't think they are at all
5 inconsistent in that respect. You just got to say
6 what is the story I am telling.

7 MR. EMMRICH: I would like to respond to
8 that. I don't disagree with what you are saying,
9 this is a very very good staff, and they have a
10 vast amount of resources, and they can do --

11 MR. MAUL: Vast resources?

12 MR. BRATHIWAITE: Maybe you know
13 something that we don't, but keep going.

14 MR. EMMRICH: You got two guys working
15 all the time on these forecasts, and they will
16 give you a very good forecast, and I would accept
17 that forecast as one of the views out there, but
18 that is not the only view. I think it is not a
19 good idea to tie yourself to only one view. It is
20 better to look at the range of forecasts out there
21 by people that spend all the time doing that. I
22 don't reject that you should do your own forecast.
23 I will welcome it, I will put it into my rating.

24 MS. KHOSROWJAH: I want to give a
25 comment on that. Maybe you averaged it

1 mathematically add them and divide them by three,
2 what you do you put them on a graph and you look
3 at what is the range, and then you make an average
4 in your head. So, that is what people do, they
5 look and say, okay, this is CEC's \$4, this is
6 NPC's \$3, and then in your head you say, oh well,
7 it is something between \$5, so you do that
8 unconsciously, so people make their own averages,
9 but it is not totally logical, that's my point.
10 It is a range.

11 I understand because different
12 assumptions goes to each different forecast, but I
13 am saying no matter if you average and divide
14 them, you put them in the same graph, and then you
15 look at them and you make your own assumptions and
16 you say, you make an average in your head, and
17 that is what everybody does.

18 MR. EMMRICH: Just as long as we all
19 don't pretend that we can actually forecast the
20 future. That is my message. I don't pretend
21 that. I've been in the business for 30 years
22 forecasting, and I don't pretend that I can
23 forecast the future, nobody can.

24 MR. MAUL: Questions for Hill or
25 comments on a particular issue?

1 MR. BRIDGES: Just a comment on that,
2 again. I mean going back to the (indiscernible)
3 study, what you were setting out to do. I think
4 it was agreed that you were going to look for a
5 reference case, and you were going to set
6 scenarios. The purpose of doing scenarios was to
7 see what the impact policy decision was on various
8 things such as how electricity generation and gas
9 demand and prices, so I think there is value in
10 understanding what your specific price forecast is
11 related to a particular outcome.

12 PRESIDING MEMBER GEESMAN: You can't
13 really do those scenarios unless you have
14 established your own reference case.

15 MR. BRIDGES: The point is, actually,
16 that you can't do any of that without a model.

17 MR. ASH: My name is Howard Ash. I've
18 sat through a lot of today's sessions, and I want
19 to echo Hill's comments here. In fact, one of
20 things that I learned working with him years ago
21 at Stanford, one of the mantras of the energy
22 modeling forum is modeling for insights about the
23 numbers.

24 The question that I would have for the
25 group here is why are we doing forecasts, and

1 let's specifically focus on gas price forecast.

2 Is the purpose of having gas price forecast so you
3 can say 10 years from now you can say well, I got
4 the price right in November 2009 within two cents.
5 I don't think so. It is what do you do about it,
6 and are you formulating policy based on your
7 forecast and on your view of the market.

8 You just made the comment about your
9 \$100 oil led you down a path (indiscernible) was
10 not the best in the state. I wonder were there
11 alternative views at the time that showed maybe
12 oil was not going to be \$100.

13 If you could even acknowledge at the
14 point, well, we think it is going to be this, but
15 we think there are some other opinions, but we
16 don't think they are valid, so we are going to
17 stick with this \$100 oil forecast, and we go
18 completely west.

19 So, what I think it is really about,
20 what are we doing this for, and what are the
21 policy questions that we are trying to answer,
22 what are the policy levers that we have. It is
23 modeling for insights, not for numbers.

24 As you do scenarios, thinking about the
25 question, what would I do differently if I knew

1 that the cold snap was going to happen in the
2 second week of December in 2009. That is the
3 question you need to ask.

4 If I could forecast variability or the
5 volatility gas price, what if I knew that gas was
6 going to be \$7 flat in 2009, averaging \$7, but
7 varying a dollar a month for 2009, how would your
8 policy change.

9 That is why we do modeling, and that is
10 why we have models. It is not to say I hit the
11 price, I hit the gas price forecast for such and
12 such a day.

13 MS. LANG: Karen Lang (inaudible), and I
14 certainly agree with Howard, I do consulting for a
15 number of large gas consumers in California, and
16 scenarios analysis for your concerns would be very
17 appropriate, but there are a lot of consumers who
18 really want to know, is gas going to go above or
19 below a certain threshold and what is a
20 volatility?

21 I think as you look for short-term
22 forecasting, you can handle volatilities that is
23 important for policy making and also
24 (indiscernible) of where gas is going to go.

25 I have seen the CEC in other

1 forecasters, even the long-term come up with
2 volatility of plus or minus 50 cents. That is
3 when you have to look at other forecasters where
4 maybe you are looking at a range of assumptions to
5 get a broader range.

6 It is important for both. What I would
7 love to see the CEC do in the improvements of
8 modeling is take a realistic look at volatility in
9 the long term and the short term. I think it is
10 important for California policy and investment
11 decision making.

12 It is not just a low price or high
13 price. We've got to be talking --

14 MR. ASH: Let's push back. What if you
15 knew the price was going to be (inaudible), how
16 would your actions change as a single consumer if
17 you knew the price was going to be real volatile
18 averaging "X" and there were going to be flat at
19 "X"?

20 MS. LANG: There are a number of
21 purchasing options you would or wouldn't take
22 based on if you knew or what the (inaudible).

23 MS. ELDER: I will give you an example,
24 budget, Texas A & M. Bi-annual budget,
25 legislature gives them money, and that is all they

1 get for the next two years.

2 They did a gas price forecast so they
3 could build that into their budget. What they
4 really need is to have some sort of like college
5 price if they are not going to have to go beyond.

6 MR. ASH: Right. My point is that if
7 volatility is really your concern, and I don't
8 know that we anybody can forecast the kind of
9 weekly or monthly volatility that folks are really
10 trying to get, but that is why the whole industry
11 of these derivatives and hedges have come into
12 being to guard against that.

13 Even if you could, and you still need
14 them, even if you could forecast those volatility
15 correctly and uses them to (inaudible).

16 UNIDENTIFIED SPEAKER: My question also
17 is, why should the California Energy Commission be
18 involved in doing a lot of volatility price
19 forecasting. I can understand why Texas A & M
20 would want to be involved in it. I am not sure --
21 I think people want to buy the story that the
22 price is volatile and understand that it is
23 volatile and that is the kind policy environment
24 you are going to work in.

25 Do you really want to have an accurate

1 forecast, is that going to change your policy if
2 you have a more accurate forecast of what that
3 volatility is going to be and when it happens. I
4 am not sure. I think I could make policy --

5 MS. KHOSROWJAH: I would like to address
6 that question because it is directly goes to
7 CPUC's actions. Because one day of the national
8 gas price is high, I mean a few days, cause all
9 the energy crisis. So, yes, it would translate to
10 different kind of policy for if we give the
11 forecast of the Energy Commission and put it into
12 our rulemaking for example, you are talking about
13 emergency reserves, you want to avoid that kind
14 of --

15 UNIDENTIFIED SPEAKER: What it means is
16 when you talk about your results, you almost have
17 to draw a swiggly line going down this thing. We
18 don't know what it looks like, but it looks like
19 that. When you present your results you do that.
20 If you project that the volatility is going to be
21 twice the level (indiscernible) or it is going to
22 have a completely different pattern, I am not sure
23 that would change the policy.

24 I could see where it would really affect
25 Texas A & M, it affects Standard, it affects a lot

1 of companies. They would want that information,
2 but I don't know why the California Energy
3 Commission wants to get involved in that issue
4 other than the fact that it really emphasized very
5 very clearly that this is an issue, it is a policy
6 issue, and we need to think about those things
7 when we set up these rules. I don't know if you
8 really want to forecast it though.

9 When I ask that question --

10 MR. MAUL: Based on the hands that I
11 have seen, I think it is Jane first, then Luis.

12 UNIDENTIFIED SPEAKER: There is one term
13 that I missed today, and I really expected to hear
14 in this discussion, and that is resource adequacy.
15 Some where along the line, I think the price
16 volatility may be important and in terms of near
17 term resource adequacy it may have some
18 importance, but I think the very real concern for
19 people in this state, is long term resource
20 adequacy of natural gas. What is this telling us
21 about that?

22 MR. MAUL: Luis, then Howard.

23 MR. PANDO: To just add to that, I think
24 that I agree with Dr. Hill that most people can
25 live with volatility. The problem is that during

1 the crisis when California saw prices that were
2 well beyond the country -- you know the whole
3 country had seen prices go up to \$8.00, there is
4 really not a lot that California can do about it.

5 It is when California's resources,
6 resource adequacy is a problem, and we see prices
7 really spike for whatever reason. I don't want to
8 get into why people believe it happened, but
9 clearly it was something uneconomic going on at
10 the time, and I think that is the thing to look at
11 and to make sure there is enough rules and
12 resources to prevent this sort of thing from
13 happening again.

14 MR. EMMRICH: I didn't quite understand,
15 resource adequacy, you mean, is there enough gas
16 available in the future.

17 UNIDENTIFIED SPEAKER: I'm talking
18 about.

19 MR. ASH: How long?

20 MR. EMMRICH: This is why we want to
21 bring LNG in. You know, that is the only way to
22 solve the problem the way we see it.

23 UNIDENTIFIED SPEAKER: (Inaudible.)

24 MR. ASH: The question of where the line
25 where resource adequacy and the geology -- where

1 geology ends and resource adequacy begins is sort
2 of a fuzzy line for me. I think when we talked
3 about very early this morning about the
4 resource -- the estimates of expanding the cost of
5 the resource.

6 Let's think about what we are really
7 talking whether the (indiscernible) should come
8 from the USGS or the NPC, or the NEB, or anybody
9 else. What are they really forecasting?

10 They are trying to forecast stuff that
11 is not the stuff that's not discovered yet. It
12 hasn't been discovered yet. There was very little
13 discussion about the level of fuel reserves and
14 stuff that they know is there.

15 Both the USGS and the NPC are both
16 trying to estimate what hasn't been discovered
17 yet. Think about that. Of course that's
18 uncertain. Of course the USGS numbers from ten
19 years ago are wrong. Of course the NPC numbers
20 from two years ago or last year are wrong. That
21 is why you need to be able to think about
22 scenarios that bring high cost role or a low cost
23 role or a high availability role or a low
24 availability role.

25 That is the power of (indiscernible) and

1 the question of what is the policy, what can the
2 CEC or the CPUC do about resource values. I would
3 argue that they can't do anything about the
4 geology. I would argue that they can't do things
5 about infrastructure.

6 If we go back fifteen or sixteen years
7 ago when there were gas curtailments in this
8 state, and the power generators in the southern
9 part of the state were running well into the
10 middle of the summer because there was no gas and
11 causing air pollution problems.

12 The CEC here is starting to look and say
13 well, we need more infrastructure, where should we
14 go get it? That is a policy decision that was
15 made to support infrastructure from a couple of
16 more prolific base at the time, and it turned out
17 to be a good policy for the state.

18 So, I think again, the issue about
19 resource adequacy has to be what can the state do,
20 what are the levers that it can effectively pull
21 and those are the kinds of questions that you need
22 to ask and not about well, can you do anything
23 about the geology.

24 PRESIDING MEMBER GEESMAN: Under the
25 framework, what are you saying, though, is that in

1 the long-term we have tools to deal with the
2 policies, and in the short-term, we don't really
3 have the correct tool, well, a fully vetted tool
4 to deal with issues like volatility.

5 So, what you are saying, Hill, is we can
6 say as a general statement that yeah, prices are
7 volatile and we can say as a general statement
8 that by virtue of that, we are going to go away
9 from the -- we will go towards fixed price
10 contracts, and we can deal with volatility that
11 way. It doesn't address a whole series of other
12 issues.

13 We did that with long-term contracts
14 with the crisis. So, you can address short-term
15 issues, but we can't necessarily analyze quite as
16 much as we would want to. We haven't really
17 determined how we would want to analyze it in the
18 short term.

19 MR. ASH: It is hard. The volatility,
20 whether you are talking about the volatility of
21 gas prices or the weather, it is hard.

22 I think one of the things when we think
23 about how gas price volatility affects you and me,
24 it's on my gas bill from PG & E. I think, though,
25 one of the ways that the regulatory system has

1 addressed that is rather than the 2025 cycle user
2 and now as a performance based system where PG & E
3 is expected to buy sort of at market whatever that
4 is.

5 I tend to like that because what that
6 tells me is we don't expect PG & E or SoCal Gas or
7 San Deigo to be able to consistently beat the
8 market. Why should we expect they are better than
9 anyone else.

10 We also expect them not to be way out of
11 the market. We think overall they are playing the
12 market and they should pay market prices that are
13 affected -- are determined by things beyond their
14 actions, but that they buy (indiscernible), and
15 that is how you deal with volatility and let them
16 come up with their own portfolio of long/short-
17 term contracts, geographical to do that. You
18 can't expect them to be below market all the time,
19 but you also should punish them if they are above
20 market, that is the kind of policy change
21 (indiscernible).

22 MR. MAUL: Jeff or Mark or George, you
23 have been awfully quiet from PG & E. Do you want
24 offer any comments at all? You have been referred
25 to several times.

1 UNIDENTIFIED SPEAKER: I guess -- this
2 discussion has been pretty wide ranging. I guess
3 the general comment that I would make is with
4 respect to this whole issue of going back to this
5 issue of using forward markets versus fundamental
6 market models. I'll call them structural markets
7 in forecasting.

8 I guess my view or PG & E's view is that
9 given that you are using long-term projections, or
10 short to long-term projections for analysis of
11 potential investments, contracts, and the like,
12 ultimately they do end up having to meet some kind
13 of market test. They are in the minor money.

14 In that sense, I think there is a
15 argument for using forward prices at least as a
16 starting point. In fact, I can tell you in
17 general, we are looking at (indiscernible)
18 contracts and the electrical people are looking
19 longer term power development issues.

20 They are looking at forward prices, at
21 least as a starting point and running scenarios
22 around those.

23 I guess the suggestion that I would make
24 with respect to forward prices is that you look at
25 them -- actually the market price reference, I

1 think is the term, in the renewables proceeding
2 calls for forward prices out six years, and then
3 pending these model driven forecasts after that.

4 I think that when you look at those
5 kinds of forward prices, one of the things that is
6 really striking is that the market -- it
7 incorporates seasonal pattern, but it also
8 incorporates this backwardation, see prices out
9 in, forward prices in 2010 of \$5.00. A lot of the
10 fundamental models that I have seen run have given
11 numbers that are quite different from that,
12 especially if you don't have LNG.

13 I guess what I would suggest is that --
14 I think fundamentally, structural models are
15 really important for doing scenarios, asking the
16 "what if" questions, and I am not in any way
17 trying to argue against their use, I think they
18 are critical, and I think we will keep talking
19 about doing this is essential for any type of
20 policy analysis.

21 I do think that there is a need at some
22 point in that forward curve to reconcile the
23 structural model with what the margin is saying,
24 at least be able to explain the differences.

25 I think one of the things I guess that

1 is striking is if you think about the
2 backwardation, and I am thinking now of Hill's
3 comment earlier about long-term price elasticity,
4 that could potentially be demanding more response
5 to price than maybe a lot of people had thought.

6 The forward market seems to be
7 consistent with that, it seems to be consistent
8 with maybe more LNG coming into the market, that
9 kind of thing.

10 I guess I am just suggesting some kind
11 of reconciliation of those two and understanding
12 what are the assumptions that are implicit in the
13 market, market's view of prices.

14 I am really now stepping back from year
15 one. I've got a chart here, but I don't have it
16 electronically, but year one and year two of a
17 forward curve are all over the place as everybody
18 has noted. If you look beyond that, there is a
19 lot more stability, and I think you may be
20 (indiscernible) about what the market believes
21 about the fundamentals of the market.

22 MR. MAUL: Jeff, can you forward that
23 chart to us electronically, so we can post it as
24 well?

25 UNIDENTIFIED SPEAKER: I can, yes.

1 I can give you a hard copy of it, but I'll forward
2 it to you.

3 MR. MAUL: Questions here, other issues
4 you want us to delve into here. You've got a
5 great group here.

6 MR. GOPAL: I just have one comment to
7 make.

8 MR. MAUL: All right, Jariam.

9 MR. GOPAL: I think we talked a lot
10 about volatility, but somehow I have a slightly
11 uncomfortable feeling.

12 I want to go back to where Ken started.
13 I just want to explore that a little further to
14 see did you want the Commission to project the
15 volatility or --

16 MS. LANG: I guess --

17 MR. GOPAL: -- consider that there is
18 this volatility in the market and express some
19 sort of boundary.

20 MS. LANG: I think we have made kind of
21 distinction between short-term and long-term, and
22 maybe volatility I think is extremely important to
23 recognize in the short-term.

24 If you are going to zero in on the
25 market in the short-term, that would be my

1 suggestion (inaudible). As consumers of your
2 forecast (inaudible).

3 In the long-term, maybe volatility is
4 more of a (inaudible). Again, what I have seen
5 come out of a lot long-term forecasters is this
6 very narrow scenarios which I just find
7 unrealistic as to if you are just tweaking one
8 little variable, when in fact, the real
9 uncertainty in long-term is much more widespread.
10 We call that volatility, uncertainty, whatever.
11 It is not just take the long-term forecast, and
12 just change the price from "A" to "B".

13 What you really want to look at is hey,
14 you really don't know what is going to happen ten
15 years out, but the possible wide-range would be
16 "X", and that is just what (inaudible).

17 MR. MAUL: Herb, you were the great
18 catalyst to start this discussion, and you got sat
19 down before we could thank you properly for the
20 presentation you made. It was very helpful.

21 MR. EMMRICH: Thank you for letting us
22 speak. We appreciate it, and we continue to work
23 with you throughout this process.

24 MR. MAUL: Okay, good. Thank you.
25 Mark.

1 MR. MELDGIN: Yeah, I have a couple of
2 questions for the CEC actually. I am Mark Meldgin
3 with PG & E. The electric side of PG & E has to
4 file very detailed resource plan with this
5 Commission by March 1.

6 In it we are going to have put in a
7 long-term price forecast for gas in order to
8 calculate rates and so on.

9 The order also asks by April 1 we come
10 up with 10 percentile and 90th percentile bounds
11 on long-term price forecasts. We are curious what
12 the CEC is going to do when they get this
13 sensitive price forecasts from different utilities
14 and meanwhile the staff is going to be developing
15 its forecast.

16 Is there going to be some mandatory
17 reconciliation in these, or how is that going to
18 happen procedurally?

19 PRESIDING MEMBER GEESMAN: We hope that
20 the submittals from the utilities provide us with
21 an appropriate benchmark by which to evaluate the
22 credibility of the staff's projection.

23 At this point, we don't envision a
24 mandatory reconciliation, but if there are wide
25 variances, would like to get everybody back

1 together and try to explore why those variances
2 occur.

3 MR. MAUL: Commissioners, do you have
4 any other burning questions you want us to
5 address?

6 PRESIDING MEMBER GEESMAN: Just in
7 wrapping up, I guess I would express appreciation
8 for everybody's sticking with it today and
9 participating in what I think was a very useful
10 conversation.

11 I still think that our efforts in this
12 area need to be driven as much by humility as
13 anything else. I think there are real limitations
14 on what the CEC can do. I think some of that
15 captured in this last discussion of volatility.
16 We need to focus on what we are capable of doing.
17 I think we have shown an ability to improve with
18 experience.

19 Much of the discussion today has
20 illustrated ways in which we can improve even
21 more. Again, I would thank everybody and welcome
22 you back to the next time we do this, which will
23 be at some point in the '05 cycle.

24 MR. MAUL: Thank you very much for
25 speaking today.

1 PRESIDING MEMBER GEESMAN: Learn by
2 doing.
3 (Whereupon, at 3:55 p.m., the workshop
4 was adjourned.)

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CERTIFICATE OF REPORTER

I, JAMES A. RAMOS, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 16th day of December 2004.

James A. Ramos

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